ENERGY REPORT
TO THE
REGULATORY FLEXIBILITY COMMITTEE
OF THE
INDIANA GENERAL ASSEMBLY
BY THE
INDIANA REGULATORY COMMISSION

October 1, 1996

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I. SCOPE OF THE ENERGY REPORTS

This is the first annual Energy Report (Electricity and Gas) to be filed by the Indiana Utility Regulatory Commission with the Regulatory Flexibility Committee of the Indiana General Assembly under IC 8-1-2.5-9. With the approval of the Committee's Chairmen, this Report is submitted on October 1, 1996. The Act specifies:

> *The commission shall, before July 1, 1996, and before July 1 of each year after 1996, prepare for presentation to the regulatory flexibility committee an analysis of the effects of competition or changes in the energy utility industry on service and on the pricing of all energy utility services under the jurisdiction of the commission.*

To be responsive to the Regulatory Flexibility Committee's charge to address specific issues, the Energy Report will provide information concerning:

1) The effects of competition or changes in the energy utility industry and the impact of competition or changes on residential rates.
2) The status of modernization of the energy utility facilities in Indiana and the incentives required to further enhance this infrastructure.
3) The effects on economic development of this modernization.
4) The traditional method of regulating energy utilities and this method's effectiveness.
5) The economic and social effectiveness of traditional energy utility service pricing.
6) Other energy utility issues the committee may consider appropriate.

Despite important similarities between gas and electric utilities and the fact that they compete against each other, there are important distinctions between electric and gas utility industries that warrant separate discussions. Because of the important distinctions between the two industries, the Energy Report is divided into separate volumes to deal with the electric and gas utility industries. We have also included appendices for the electric and gas volumes that contain more detailed information on various topics. The Electric and Gas Volumes are intended to provide the General Assembly with an unbiased and reasonably comprehensive discussion of emerging competition in the electric and gas industries.

While we anticipate the General Assembly will be primarily interested in competition issues, it is important to describe the changing structures of these industries. The changing structure of these two industries, that have a long tradition of monopoly and regulation, has largely been the result of changes in federal law and federal regulatory policy designed to promote competition. For this reason, the Energy Report discusses the basic structures of the gas and electric industries in the context of utility regulation.

II. EXECUTIVE SUMMARY

Introduction

The natural gas industry has been in a state of flux since the late 1970s when the federal government began deregulating production prices and interstate pipeline services and by doing so, opened the door to wholesale competition. The first to take advantage of the new environment were the large industrial customers which were once captive customers of their local distribution companies, or LDCs. As a result of the federal regulatory changes, these large customers were allowed to directly contract with producers and marketers for natural gas. The only type of transaction left between the large customers who declined to buy their gas from the LDCs and the LDCs was the transportation of gas from the interstate pipeline to the customer's place of business.

Still captive to the LDCs are the smaller industrial, commercial and residential customers. However, in the last few years, choice for customers at each level of service has begun to take shape. Pilot programs to allow the smaller customers to choose their supplier have sprung up in several regions in the US. Northern Indiana Public Service Company has a proposal before the IURC to implement the first pilot program of this kind in Indiana.

Because of the ability of large industrial customers to shop for low-cost energy, gas prices have fallen for those customers.

As the momentum for customer choice increases and questions about the applicability of traditional regulation are asked, it is critical that decision makers understand how the industry is changing and how state regulation might also need to change to meet the demands of the new environment . Further, it is critical that the General Assembly be mindful of the captive customers and the need to mitigate any detrimental effect if the regulatory process is changed.

The IURC is faced with conflicting objectives in dealing with the competitive forces facing the LDCs. On one hand, the IURC must protect the customer and ensure that utility services remain safe, reliable, widely available and at high quality but at reasonable rates. The IURC must also ensure that the LDCs are treated equitably, which in the changing environment could mean that they are given price flexibility and the ability to compete with unregulated entities that offer similar services in a timely manner.

In order to compete in the new regulatory environment that allows their largest -- and most lucrative -- customers to decline all or part of their services, the LDCs have placed increased reliance on non-regulated gas marketing affiliates, which can compete on the open market. By taking advantage of the unregulated market in this way, the LDCs can then sell at lower retail rates and retain some of the customers they might otherwise lose.

Senate Enrolled Act 637, I C 8-1-2.5, allows the energy utilities the flexibility to adapt to market changes. The act allows the IURC, when requested by a utility, to move from historic rate-based regulation to alternative regulation, if that is found to be in the public interest.

Background

Nationwide, the natural gas industry provides about 25 percent of all energy consumed in the United States. It supplies nearly one-half of residential and commercial customers' energy needs and about 43 percent of the nation's industrial customers' energy needs.
Natural gas usage in the US is expected to increase as the century closes, in part because it is an abundant, relatively clean-burning and competitively priced fuel. Also, 93 percent of the natural gas used in the US is produced in the US with most of the remaining 7 percent coming from Canada. Most experts believe that the US has ample long-term supplies of natural gas remaining.

There are four major operational divisions within the natural gas industry:

- Production companies extract the natural gas from the Earth
- Transmission companies transport natural gas through interstate pipelines
- Distribution companies deliver the natural gas to customers
- Marketing companies acquire, gather, and store gas, and finance companies that buy gas from the producers.

The Federal Energy Regulatory Commission has regulatory oversight of the transmission companies. In 1992, the FERC, in its Order 636, unbundled the sales and transportation services offered by the interstate pipeline companies and ordered those services to be offered separately. In doing so, the FERC made the LDCs responsible for procuring their gas supplies independently of the interstate pipelines. The LDCs retained their responsibility to supply gas at the local level. Regulation of the LDCs was left to the state utility commissions.

The IURC's Role

More than 1.6 million Indiana customers receive gas service from 39 different LDCs. The IURC regulates 24 of those LDCs, which together generated more than $1.3 billion in revenue last year. Of the 24 LDCs, 20 are investor-owned and four are municipals. The remaining 15 utilities are owned by municipalities and have each withdrawn from the IURC's jurisdiction pursuant to Indiana statute.

The four largest LDCs in Indiana are the Northern Indiana Public Service Company, (NIPSCO) Indiana Gas, Citizens Gas and Southern Indiana Gas & Electric Company (SIGECO.) Together, they serve more than 90 percent of Indiana's natural gas customers. All four of these companies are considered financially sound by the financial community. They have favorable business positions; their gas operations, as well as their finances, are solid, and their managements are considered to be proactive.

Indiana's LDCs are supplied by eight interstate pipelines, which criss-cross the state and compete for wholesale customers, i.e., LDCs and large industrial customers. Because of the presence of so many pipelines, more than half of Indiana's LDCs use more than one supplier and actively shop the market for better priced natural gas.

Approximately 60 percent of the LDCs' costs are directly attributable to the cost of acquiring natural gas. The gas companies file quarterly or biannual requests for gas cost adjustments to their rates to reflect and recover the changing costs of gas which they pay gas producers in order to acquire the natural gas they then sell to customers.

The LDCs are allowed to pass on to customers the full cost of purchased gas, They are prohibited, however, from earning a profit on their bulk purchases. The IURC monitors whether the LDCs are buying at the best possible costs through the gas cost adjustment, or GCA procedure.

Recent attention has been focused on the GCAs due to the severe winter of 1995-6, during which wholesale gas prices across the US rose dramatically and unexpectedly. This forced the affected LDCs to pay higher prices in order to meet the supply demands of their customers. Because of the structure of the

GCA procedure, the LDCs were selling to their customers gas at prices lower than those which the LDC had paid. In correcting this under-collection through the GCA, many of the state's LDCs have recently received approval for passing on to customers these costs, some of which resulted in a substantial percentage increase in residential bills as compared to last year.

The GCA procedure allows LDCs to pass on to customers changes in the wholesale price of gas. It also reduces the frequency with which LDCs must file petitions with the IURC to increase their rates and charges due to the increased cost of gas. This aspect of state regulation benefits customers by reducing the costs the LDC may recover in rates.

The GCA procedure allows the IURC to regularly monitor whether the companies are earning in excess of the rate of return assigned to them in their last base rate case. If the LDCs are over-earning, they are required to refund that over-earning to customers through reduced rates. At one time, in accordance with Indiana statute, the IURC used a one-year history of revenue collections to monitor whether the utilities were over-earning. The General Assembly in 1995, under I C 8-1-2.5, changed the GCA process and extended the period for the earnings calculation to five years, or the period since the last rate case, whichever is longer.

When establishing base rates for the LDCs through a traditional rate case, the IURC not only takes into account the cost of acquiring and delivering the gas to customers but also allows a reasonable rate of return on investment for the investor-owned LDCs and a reasonable rate of return on net plant for the municipally owned utilities.

The IURC has allowed its LDCs some pricing flexibility in the interest of retaining or attracting large industrial customers. In certain instances, LDCs have been permitted the ability to negotiate some flexibility in rates, volume conditions and other factors, which allowed them to encourage large users to stay on their systems. Because the loss of large customers to the LDCs could result in the remaining customers having to make up the revenue losses, the IURC has permitted flexible pricing on a case-by-case basis.

Developments Toward Regulatory Reform in Indiana

NIPSCO'S ARP

On November 29, 1995, pursuant to the provisions of Senate Enrolled Act 637, NIPSCO became one of the first LDCs in the United States to file for unbundling of its gas distribution services. The NIPSCO petition requesting alternative regulation would allow, as a pilot program, among other things, some of its customers to choose their natural gas supplier. This Alternative Regulatory Plan, or ARP, is at the forefront of alternative regulation. As a result, it has sparked considerable interest among LDCs, interstate pipeline companies, marketers, consumer groups and industrial customers.

The NIPSCO ARP has yet to reach an evidentiary hearing, in part because settlement conferences were held among several of the parties prior to NIPSCO filing the details of its ARP. The IURC did not sponsor the settlement conferences, but did allow time for the negotiations to take place should the parties choose to voluntarily participate. The settlement conferences were designed to allow NIPSCO to meet with the interested parties and craft a consensus on the contents of the ARP.

Senate Enrolled Act 637 provides a method for NIPSCO and other LDCs to petition for alternative regulation.

ProLiance

Indiana Gas Company and Citizens Gas & Coke Utility in early 1996 formed a company called ProLiance, which has been used to administer each utility's gas supply and portfolio, and provide sales, administrative and marketing services to the utilities' current customers since March 1996. ProLiance will also market its products and services to other LDCs and customers in Indiana and other states. In entering into the joint venture, the utilities claimed ProLiance would allow the companies to acquire better prices for gas, which would result in lower rates for customers.

A group of industrial customers, consumer advocates, marketers and other utilities have protested the formation of ProLiance. At issue is the affiliate interest among Indiana Gas, Citizens Gas and ProLiance and the concern expressed by some of the parties that the two LDCs may receive more favorable treatment from ProLiance than will its other customers.

Another concern of some of the parties is that the LDCs may not return to customers all appropriate savings gained through the joint venture and that because ProLiance is unregulated, the IURC would have no opportunity to ensure that customers receive all the benefits to which they are entitled.

The IURC is in the process of adjudicating these issues and anticipates a decision by the end of the year.

Marketing Affiliates

Enron Capital & Trade Resources Corp., a gas marketer, asked the IURC to issue rules establishing a statewide standard of conduct governing the relationship between LDCs regulated by the IURC and their marketing affiliates. Many of Indiana's LDCs already have marketing affiliates, which sell gas to customers served by the LDC as well as others outside the exclusive territory of the LDC. Enron claimed that the relationship between the regulated LDC and an unregulated marketing affiliate carries the potential for undue preference and favorable treatment of the affiliate and its customers. Such proposed regulations would require that the IURC have jurisdiction over the marketing affiliates of LDCs, an issue which is in dispute in the ProLiance proceeding.

The IURC dismissed Enron's request for rules on July 18, 1996, because the initiation of rulemakings is the express domain of the IURC and may not be sought through a docketed proceeding.

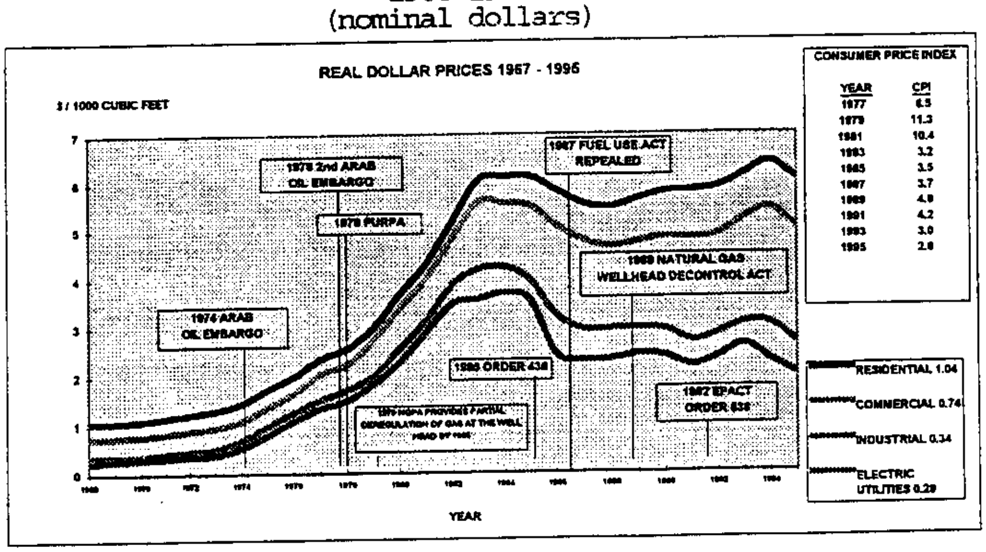
Conclusion

This is a challenging time for state lawmakers, regulators and utilities as they consider the best manner in which to proceed as they contemplate changes in the natural gas industry. In subsequent energy reports, the IURC will continue to apprise the General Assembly of the status of changes in the natural gas industry.

III. INTRODUCTION TO THE GAS REPORT

The interest in enhanced competition in the natural gas industry, like the electric industry, is fueled by the prospect of lower prices for consumers and the potential for increased profitability of natural gas suppliers. Empirically, there is reason to be optimistic that these two objectives can be satisfied. The following graphs detail the experience of natural gas prices over the last three decades. During this time span, the nation's natural gas industry has evolved from a highly regulated industry to an industry with substantial competition in the production and pipeline transportation segments. While there has been competition for the largest customers during the past few years, competition for all customers is in its infancy in only a couple of states. These graphs depict changes in federal law and regulation with respect to changing economic conditions. These graphs also show that, while all customers have benefited in recent years from moderating gas prices, larger customers have realized most of the benefits of an increasingly competitive natural gas market. The fact that the larger customers have benefited most from competition stems from the ability of large customers to tailor their gas supply portfolio to their unique circumstances. Events in the gas industry have made it possible for larger customers to make direct purchases of gas from producers and arrange other services such as storage and pipeline transportation rather than purchasing the bundle of gas services from a Local Distribution Company (LDC).

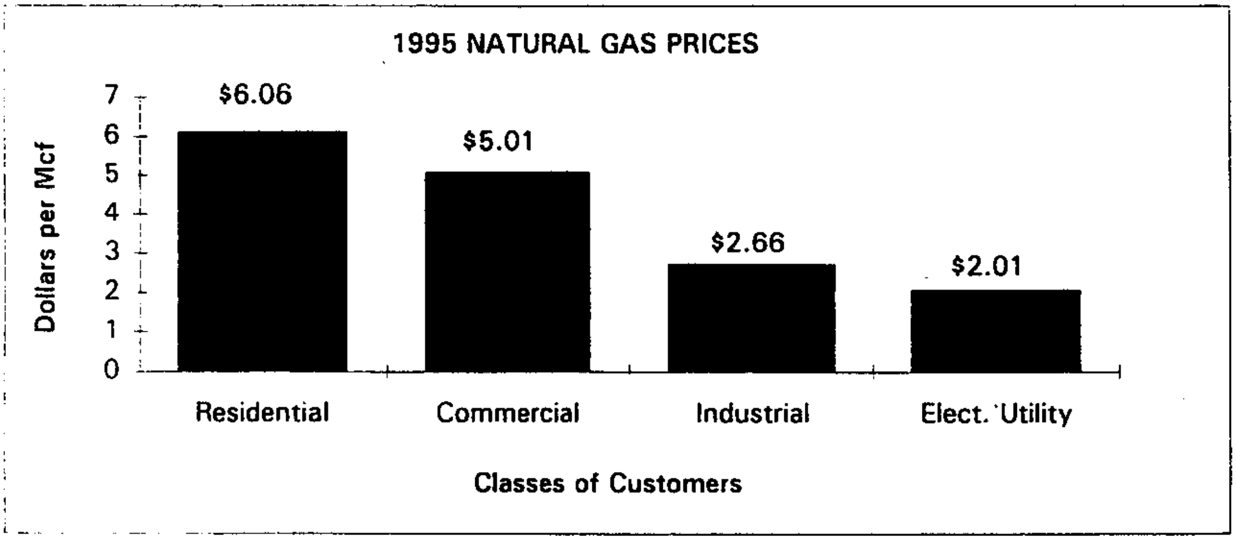
GRAPH 1
THE PRICE HISTORY OF NATURAL GAS
1968-1995
(nominal dollars)



Annual Energy Review 1995 United States Department of Energy/Energy Information Administration July 1996

The following graph depicts natural gas prices for 1995.

GRAPH 2
1995 NATURAL GAS PRICES



The following two tables compare the price of gas delivered to utilities (the citygate price) throughout the United States. These tables also show the average prices charged to various types of customers.

TABLE 1

THE PRICE OF NATURAL GAS IN THE UNITED STATES
A STATE-BY-STATE COMPARISON

1996 YTD Est. Avg ($/MCF) City-Gate		1995 Average ($/MCF) City-Gate		1994-1996 Average Prices ($/MCF)		
Price	STATE	Price	Price	Residential	Commercial	Industrial
1.53	New Mexico	1.50	2.24	3.88	3.18	2.89
1.58	Alaska	1.68	1.66	3.32	2.34	1.51
2.03	Washington	2.43	2.44	5.41	4.52	2.51
2.05	Idaho	2.18	2.42	5.00	4.43	3.26
2.13	Colorado	n/a	3.36	4.04	3.64	1.80
2.14	Oregon	2.45	2.72	5.90	4.86	3.27
2.14	Arizona	2.16	2.78	6.76	4.93	3.92
2.23	Utah	3.58	3.06	4.41	3.41	2.09
2.32	California	1.93	2.97	6.34	6.29	3.86
2.53	Arkansas	2.35	2.7	5.28	4.34	3.03
2.55	Oklahoma	2.75	2.70	4.84	4.50	2.88
2.59	Missouri	2.37	2.90	5.27	5.11	4.57
2.61	Nebraska	2.35	2.90	4.81	n/a	3.17
2.62	Nevada	2.86	3.28	5.74	4.83	4.96
2.73	Kansas	2.14	2.80	5.14	4.09	2.61
2.75	North Dakota	n/a	3.26	4.26	3.83	3.32
2.78	Montana	3.32	3.59	4.63	4.61	4.80
2.82	South Dakota	2.81	3.26	4.49	3.69	1.92
2.83	Minnesota	2.43	2.84	4.92	4.4	2.99
2.84	Wisconsin	2.66	3.18	6.82	4.72	3.82
2.86	Vermont	2.40	2.93	6.02	5.23	3.54
3.01	Iowa	2.60	3.14	4.71	4.06	3.29
3.06	Michigan	2.85	2.90	4.45	4.45	4.05
3.07	Kentucky	2.81	3.34	4.81	4.49	3.78
3.14	**U.S. Avg.**	2.75	3.19	5.75	5.21	3.47
3.19	Texas	3.17	3.24	5.18	4.42	1.89
3.21	Alabama	2.55	3.30	6.33	5.84	3.97
3.23	**Indiana**	**2.64**	**3.13**	**4.84**	**4.17**	**3.30**
3.25	New York	2.44	3.24	7.76	n/a	n/a
3.26	Illinois	2.37	3.27	4.53	4.33	4.05
3.32	Mississippi	2.32	2.97	5.10	4.67	3.49
3.33	Tennessee	2.46	2.49	5.88	5.56	3.76
3.33	West Virginia	2.75	3.44	6.82	6.11	2.77
3.33	Massachusetts	2.97	3.74	8.9	7.42	6.97
3.38	Pennsylvania	3.04	3.43	6.60	6.00	4.34
3.38	Louisiana	2.15	2.89	5.69	5.59	2.67
3.46	Delaware	2.54	3.30	6.31	5.38	3.95
3.58	New Jersey	3.11	3.45	7.06	8.06	4.36
3.59	Maryland	2.59	3.25	6.74	5.84	7.76
3.59	Georgia	2.9	3.56	5.70	5.44	4.68
3.63	North Carolina	2.81	3.39	6.71	5.90	4.64
3.63	Virginia	2.90	3.44	6.98	5.56	4.51
3.76	Florida	2.50	3.18	9.98	6.41	4.32
3.87	Rhode Island	2.84	3.70	7.70	7.04	5.45
3.93	Ohio	3.93	3.51	5.20	4.91	4.51
3.94	South Carolina	3.11	3.60	7.28	6.41	1.92
3.95	Maine	3.07	3.91	7.54	7.03	6.15
4.07	New Hampshire	n/a	3.26	7.17	6.86	5.56
5.22	Connecticut	4.66	3.47	9.89	7.77	5.72
5.54	Hawaii	5.13	4.40	18.75	13.44	n/a

Source: NATURAL GAS MONTHLY June 1996 pgs. 49, 52, 55, 58 Energy Information Administration Dec. 1995

TABLE 2
MONTHLY GAS PRICE & RANKINGS FOR THE
27 LARGEST CITIES IN THE UNITED STATES

NAME OF CITY	RESIDENTIAL	SM.COMMERCIAL	LG.COMMERCIAL	INDUSTRIAL
EL PASO	$39.07 (1)	$45.48 (1)	$190.52 (1)	16,088 (1)
DENVER	48.08 (2)	50.57 (2)	217.24 (2)	18,223 (2)
SAN ANTONIO	57.81 (3)	57.81 (3)	282.66 (4)	21,809 (7)
DETROIT	60.37 (4)	72.30 (11)	302.46 (7)	26,527 (14)
SEATTLE	61.30 (5)	63.72 (4)	301.66 (6)	29,735 (19)
MEMPHIS	61.36 (6)	64.55 (5)	237.00 (3)	21,383 (5)
AUSTIN	61.80 (7)	65.99 (6)	395.38 (19)	24,713 (11)
HOUSTON	63.67 (8)	73.08 (13)	300.02 (5)	33,189 (23)
NEW ORLEANS	64.35 (9)	68.03 (9)	326.04 (10)	27,611 (16)
DALLAS	66.49 (10)	72.43 (12)	399.63 (20)	21,782 (6)
CLEVELAND	66.87 (11)	66.87 (7)	317.34 (8)	28,752 (17)
COLUMBUS	67.77 (12)	67.77 (8)	317.58 (9)	24,946 (12)
INDIANAPOLIS	**72.58 (13)**	**68.78 (10)**	**328.23 (12)**	**22,496 (8)**
SAN JOSE	74.92 (14)	91.24 (22)	440.41 (23)	23,034 (9)
CHICAGO	75.40 (15)	87.97 (20)	340.38 (13)	25,822 (13)
SAN FRANCISCO	76.39 (16)	91.24 (23)	440.41 (24)	23,034 (10)
NASHVILLE	76.73 (17)	85.71 (19)	387.41 (17)	20,901 (4)
BALTIMORE	78.98 (18)	82.34 (17)	352.84 (15)	29,873 (20)
PHOENIX	84.00 (19)	81.34 (16)	390.94 (18)	29,213 (18)
MILWAUKEE	84.26 (20)	74.85 (14)	341.99 (14)	31,092 (21)
PHILADELPHIA	86.47 (21)	94.92 (24)	431.14 (22)	34,761 (24)
LOS ANGELES	88.36 (22)	85.23 (18)	376.08 (16)	32,751 (22)
SAN DIEGO	89.38 (23)	87.97 (21)	421.01 (21)	19,331 (3)
JACKSONVILLE	90.42 (24)	80.33 (15)	327.58 (11)	26,887 (15)
WASHINGTON	96.78 (25)	99.43 (25)	471.26 (26)	na
BOSTON	116.48 (26)	127.94 (27)	523.06 (27)	45,951 (26)
NEW YORK	116.68 (27)	111.60 (26)	460.41 (25)	37,873 (25)

Compiled by the Colorado Public Utilities Commission July 1994: 1) Rates in effect April 1, 1994 -exclusive of taxes 2) Gas usage based on: Residential. = 120 CCF, Sm Commercial = 120 CCF, Lg Commercial = 602 CCF and Industrial = 6,024 MCF

As the natural gas industry becomes increasingly competitive and takes on more of the traditional attributes of a commodity such as agricultural products, there is an expectation that the price differentials between regions, local distribution companies and types of customers would diminish. In a competitive market, unwarranted price differentials provide an opportunity for competitors to fill the niche and mitigate those differences. The commoditization of gas does, however, have some significant inherent roadblocks. First, unlike electricity, gas can not move at speeds approaching the speed of light so there will be some differences in prices among regions of the country. "Freeze-offs" in the gas producing states always exacerbate this physical limitation. Second, regional differences will continue because pipelines will always be a "bottleneck" to some extent. Bottlenecks in the transportation of natural gas will always be particularly acute during periods of extraordinary demand in specific regions.

In addition to the endemic barriers to commoditization, there are other problems that will have to be addressed to limit price differentials. First, the extent and timeliness of information concerning prices for gas, transportation and ancillary services could be a critical limiting factor. While the FERC and the gas industry are taking steps to address this concern, success is not a certainty. Second, the equalization of prices among customers will be a function of the ability of smaller customers to "aggregate" their loads so that they can exercise market power on par with the largest customers.

Much of the groundwork for a competitive natural gas industry has been done by the federal laws and regulations that provide competition among producers and more efficient transportation of natural gas. There is significant work that remains. There are now a few experiments to test the efficacy of competition behind the citygate. There are, however, no experiments currently underway in Indiana to provide guidance on the critical policy issues that will confront the General Assembly and the Indiana Utility Regulatory Commission.

IV. THE STRUCTURE OF THE NATURAL GAS INDUSTRY IN INDIANA

There are 20 investor-owned gas utilities and 19 municipal utilities. Of these, 4 city-owned gas utilities including Citizens Gas (a public trust).

There are 8 major pipelines in Indiana that serve investor-owned and city-owned distribution systems. A map of the Indiana gas utilities and pipelines in Indiana is contained in the Executive Summary. These pipelines provide service to some of Indiana's largest customers (e.g., steel firms). From an economic perspective, Indiana is in a superior position relative to other gas utilities since industries in many other states are served by only 1 or 2 major pipelines. The number of competing pipelines, is one of the major factors in maintaining lower average prices for Indiana consumers. The following charts are intended to give the reader a perspective on Indiana's largest utilities as well as a regional and national perspective.

TABLE 3
RESIDENTIAL CUSTOMERS

Utility	Number of Customers	Average Cost Per Mcf
Citizens Gas	231,864	$5.20
Indiana Gas	421,568	$5.57
SIGECo	93,842	$4.34
NIPSCo	583,404	$5.25
Total & Averages	1,330,678	$5.28

TABLE 4
COMMERCIAL CUSTOMERS

Utility	Number of Customers	Average Cost Per Mcf
Citizens Gas	20,204	$4.09
Indiana Gas	44,660	$4.77
SIGECo	8,944	$3.26
NIPSCo	47,256	$4.50
Total & Averages	121,064	$4.41

TABLE 5
INDUSTRIAL CUSTOMERS

Utility	Number of Customers	Average Cost Per Mcf
Citizens Gas	729	$3.07
Indiana Gas	1,171	$2.91
SIGECo	222	$2.65
NIPSCo	3,701	$3.85
Total & Averages	5,094	$3.26

SUMMARY FOR ALL CLASSES OF CUSTOMERS

Total Revenue: $1,184,296,954
Total Volumes: 249,722,979
Average Cost: $4.74

GRAPH 3

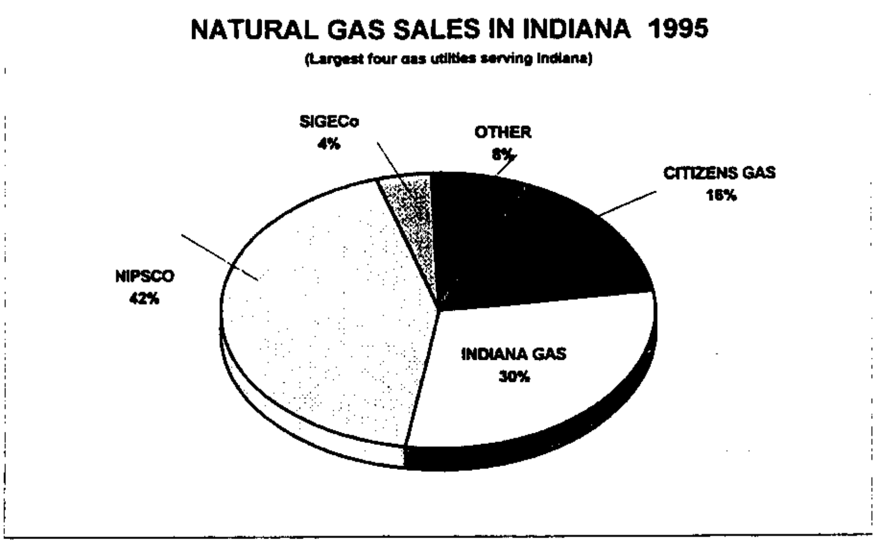


TABLE 6

NATURAL GAS DELIVERIES BY STATE

Residential Consumers
(million cubic feet)

STATE	1994	1995	1996
Indiana	84,534	75,104	87,239
Illinois	242,866	219,198	248,473
Kentucky	34,464	30,994	32,843
Michigan	188,908	165,254	189,520
Ohio	179,418	161,898	171,114
Wisconsin	64,864	58,623	68,155
United States	2,424,951	2,166,074	2,504,023

TABLE 7

NATURAL GAS DELIVERIES BY STATE

Commercial Consumers
(million cubic feet)

STATE	1994	1995	1996
Indiana	38,871	36,094	41,868
Illinois	96,198	88,102	94,905
Kentucky	18,941	17,138	19,905
Michigan	89,066	77,982	89,793
Ohio	85,614	79,310	89,900
Wisconsin	37,424	34,893	42,265
United States	1,261,350	1,190,542	1,357,648

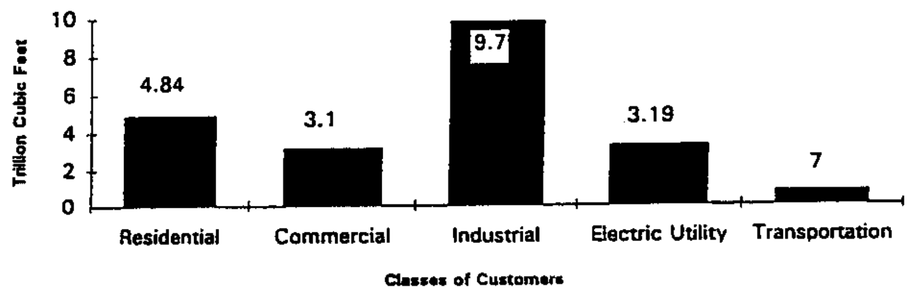
TABLE 8

NATURAL GAS DELIVERIES BY STATE

Industrial Consumers
(million cubic feet)

STATE	1994	1995	1996
Indiana	79,563	85,787	79,926
Illinois	98,809	94,944	105,471
Kentucky	23,770	27,259	26,010
Michigan	102,024	95,450	105,402
Ohio	94,782	100,073	103,924
Wisconsin	44,246	46,425	48,208
United States	2,197,952	2,213,084	2,290,252

GRAPH 4
1995 NATURAL GAS SALES IN THE UNITED STATES
(TRILLION CUBIC FEET)



A. **Financial Analysis Of Indiana Utilities**

Indiana investor-owned gas utilities are in good financial position as based on Standard & Poor's (S&P) utilities rating criteria. The bond ratings for Indiana's investor-owned gas utilities show that none have a rating below "A".

TABLE 9

FINANCIAL STRENGTH OF INDIANA LARGEST IOU GAS UTILITIES

Name of Utility	S&P Bond Rating	- Per Share- Earnings	Dividend	Div Payout	Operating Revenue ($mill)
Indiana Energy	AA-	$1.83	$1.10	60%	$ 445.1
NIPSCo	A	2.72	1.68	62	1,722.3
SIGCORP	AA	2.44	1.73	71	338.7

Source: C.A. Turner Utility Reports May 1996

The S&P's utilities rating methodology assesses financial risk by identifying the strengths and weaknesses of financing methods on a historical basis. The business risk is assessed by the aggregated measure of the utility's profitability focusing on the future of that utility within the industry. The following information comes from Standard & Poor's Utilities Rating Service, Standard & Poor's Creditweek Municipal, and Value Line Investment Survey.

1. Indiana Gas

Indiana Gas Co., a subsidiary of Indiana Energy Inc, (IEI), has a strong corporate credit rating of "AA-" with a stable outlook. This rating reflects an above average business position, healthy service territory, diverse gas supply, and strong financial profile. Indiana Gas has vibrant customer growth which consists of more than 75% residential and commercial market share. The utility's gas supply is diverse and abundant with access to multiple interstate pipelines. Indiana Gas has a strong competitive position with low costs and rates.

In March 1996, Indiana Gas & Citizen's Gas & Coke announced that their jointly owned gas marketing company, PROLIANCE ENERGY, will begin operations in April 1996. The agreement states that Proliance will supply gas and portfolio administration services for Indiana Gas and Citizens Gas & Coke Utility, and their combined customers. Proliance will also provide gas sales, administration, and marketing services to customers of Indiana Energy Services and a subsidiary of Citizens, CESCO. Proliance is expected to be advantageous for Indiana Gas since it is intended to be outside of regulatory scrutiny. Currently, there are three proceedings before the Indiana Commission that may affect Proliance's formation, operations and earnings.

According to the American Gas Association,[1] Indiana Gas has unbundled its services for medium volume commercial and industrial customers using 5,000 to 50,000 dekatherms per year. Indiana Gas is in the process of developing an aggregated transportation program for smaller customers.

2. Northern Indiana Public Service Company

Northern Indiana Public Service Company (NIPSCo), a subsidiary of NIPSCo Industries Inc, has a corporate rating "A" with a "stable outlook". This represents a risky business position but a healthy financial state. NIPSCo has proactive management and solid gas operations. NIPSCo provides electric and gas service with gas service representing 40% of utility operating revenues and 26% of assets. NIPSCo is the largest gas distribution company in Indiana and the 14th largest U.S. gas distribution company in terms of deliveries. NIPSCo has low-cost operations, competitive rates, direct access to almost every major gas supply basin, and an excellent performance record.

NIPSCo filed with the Indiana Commission, in late 1995, a proposal to unbundle virtually all of its gas distribution services. A decision from the Indiana Commission is pending.

3. Southern Indiana Gas & Electric Company

Southern Indiana Gas & Electric Company (SIGECo), a subsidiary of SIGCORP, Inc, has a corporate credit rating of "AA" with a "stable outlook" reflecting a favorable business position. SIGECo provides electric and gas services with gas services representing approximately 21% of utility operating revenues. SIGECo's gas business has a low-cost operation which recently ranked second lowest in the Indiana Commission's latest residential gas bill comparison for Indiana. The Indiana Commission recently granted SIGECo's application to merge with Lincoln Natural Gas, a relatively small distribution utility, and consolidate rates into one set of rates for all SIGECo customers.

SIGECo withdrew its filing that asked the Commission to consider Alternative Ratemaking.

4. Citizens Gas & Coke Utility

The Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis, a successor trustee of a Public Charitable Trust, doing business as Citizens Gas & Coke Utility a municipal utility that provides gas service to the Indianapolis metropolitan area. Citizens Gas & Coke's revenue bonds have a rating of "AAA". Other debt obligations are rated at "A" or above. Citizens has a diverse service area, a flexible natural gas system and is financially solid. The Utility's primary sources of natural gas includes the Panhandle Eastern Pipeline Company and Texas Gas Transmission Corporation.

B. Initiatives By Indiana Utilities Post IC 8-1-2.5-9

To date only Northern Indiana Public Service Company (NIPSCo) has filed under the new authorities of IC 8-1-2.5-9 allowing utilities to request Alternative Regulatory Plans. There are, however, two other filings of note. The PROLIANCE filing entails a proposal by CITIZENS GAS & COKE and INDIANA GAS to form a subsidiary that would be responsible for gas procurement for the two gas utilities. The final filing of note was by ENRON. Enron requested the Commission undertake a rulemaking to adopt "CODES OF CONDUCT" for utilities in their dealings with their affiliates.

1. The NIPSCo Alternative Regulatory Plan (ARP)

The following is a compilation of public comments that NIPSCo has made concerning their filing in Cause 40342. These excerpts are contained in Executive Summaries of the Direct Testimony that was prepared for the Commission and other parties and provided to the IURC on August 30, 1996. While this is the first case to be filed under Senate Bill 637, it should be noted that the following statements are not intended to reflect the Indiana Utility Regulatory Commission's views concerning the issues raised in this Cause or prejudge the merits of NIPSCo's proposal.

Company's Proposal

Customers, as well as competitors, are demanding alternatives to services available under traditional retail rates and regulation. The Company viewed it as a prudent management decision to be a leader in the industry and the first Indiana utility to propose a comprehensive ARP (alternative regulatory plan)...Company representatives report that customers are requesting access to unbundled service options. The Company's market survey indicated that almost 60% are interested in increased customer choice. Northern Indiana determined that the ARP should be comprehensive and include a substantial pilot program for small volume users, including residential and small general service (commercial) customers.

The best way to lead to a managed transition was to file an ARP that creates a platform for Northern Indiana to provide a host of new competitive services, coupled with an unbundling proposal that will give all customer classes access to various suppliers, including Northern Indiana...Northern Indiana's ARP consists of four major elements:

1) a proposed pilot program that extends supplier choice to all customers, including small users;

2) a series of new service proposals in addition to current services;

3) proposed enhancements to existing services;

4) a proposed Gas Cost Incentive Mechanism ("GCIM") and storage incentive mechanism.

The delivered cost of natural gas will likely decline if the ARP is approved because the system utilization factor will improve. Currently, the system is being utilized on an average day at load factors that are below system design. Second, there will be...competition from third party suppliers...and small users will have service options...which should allow consumers to lower their costs. Third, approval of the GCIM will give Northern Indiana a financial incentive to assume prudent portfolio risks without jeopardizing system reliability. The shared cost savings will benefit consumers because their costs will be lower and the Company because of the sharing of savings.

1) SMALL CUSTOMER PILOT PROGRAM

[T]he proposed small customer unbundling pilot [is] a two-year program that would give a defined group of residential and small commercial customers the option to buy their gas supply from suppliers other than Northern Indiana by electing Supplier Choice Delivery Service ("SCDS") or Firm Distribution Transportation Service ("FDTS")...Suppliers that participate in the unbundling pilot would contract with Northern Indiana...and would have to meet certain "qualification

requirements"...Northern Indiana expects the unbundling pilot to function as a test to give it a better understanding of the issues associated with supplier choice and service unbundling...Northern Indiana is willing to act as a supplier of last resort...SCDS service includes supplier of last resort, back-up service. For other unbundled services, like FTDS, no-notice back-up service ("FNBS") is available as an option. An important element of that service option is that customers who want the service will have to contract and pay for it.

2) NEW SERVICES

New market based services...are designed to provide alternatives to services currently being offered by other deregulated and regulated competitors. These services include a Gas Parking Service ("GPS"); a Gas Lending Service ("GLS"); a Firm Peaking Capacity Service ("FPCS"); and a Firm No-notice Back-up Service ("FNBS"). These services are designed to meet the load management and balancing needs of large industrial users as well as marketers and supplier/brokers...These services are not offered exclusively by Northern Indiana. Thus, the Company proposes to offer them at negotiated market based prices.

3) PROPOSED ENHANCEMENTS TO EXISTING SERVICES

The Company propos[es] a gas sales service for large industrial users as well as a modification of existing services that will allow the Company to customize the gas commodity component of an otherwise bundled sales service...These tariffs apply to those markets where there is gas-on-gas or alternate fuel competition, in which case the Company must have the ability to customize its gas commodity price and its effective delivered price to be competitive...Northern Indiana is not asking for the right to strip cheap gas supplies out of its GCA so that it can offer a "subsidized" gas supply to selected customers.

Code of Conduct in Dealing with Affiliates

[T]o the extent that a Northern Indiana marketing affiliate requests and receives any utility service, it will receive service on a non-discriminatory basis, as do all customers. Services negotiated with an affiliate, as well as the terms and conditions of service, will be available to other marketers...

4) GAS COST INCENTIVE MECHANISM AND STORAGE MECHANISM

[T]he GCIM is an alternate mechanism to traditional gas cost pass-through. An accepted and published benchmark price would be used for supply areas in which the Company acquires gas supply. To the extent the Company's actual cost for supply area purchases is less than this established benchmark price, the Company and customers would share the cost savings on a predetermined percentage basis. The greater the cost savings, the greater the Company's share of the savings. Conversely, if gas costs are higher than the benchmark, the Company would absorb, on a shared basis with customers, the negative differential.

The Company has also proposed an incentive mechanism associated with optimization of the value of its storage gas above plan levels. Savings in gas supply costs will be shared equally between shareholders and customers.

Northern Indiana's primary objective is to reduce the overall gas costs... Innovation in portfolio acquisition and proactive participation in today's market is discouraged because there are no rewards for attempting to lower gas costs through non-traditional portfolio management...The initial step in developing a GCIM was to identify a Benchmark to use as the standard of measurement for the gas supply component of its portfolio...The monthly average of the daily postings from Gas Daily, and the monthly average prices from <u>Natural Gas Week</u>

were averaged to provide an average daily price of gas...In order to take into account the reservation costs associated with maintaining winter and long-term deliverability levels, the GCIM calculation will be adjusted by a percentage increase of 5%...("tolerance band").

The difference between the Benchmark price of gas and the actual cost will be the measure of Northern Indiana's commodity purchase performance...If [there is a] Positive Performance between 0% and 1%, Northern Indiana's share will be 30% of the amount. If the Positive Performance is between 1% and 3%, the Company's share will be 50%...For any positive performance greater than 3%, the Company's share will be 70%...If Northern Indiana's actual purchases are greater than the Benchmark dollars, this scenario is classified as a Negative Performance. If the Negative Performance is between 0% and 5%, 100% [is borne by] the customers. If the Negative Performance is between 5% and 6%, the customer's share is 70%...If the Negative Performance is between 6% and 8%, the customer's share is 50%. For any Negative Performance greater than 8%, the customer [bears] 30% of the amount.

2. The Proliance Proposal By Citizens Gas & Indiana Gas (Cause 40437)

The Petitioner's have asked the IURC to disapprove the contracts and agreements between Indiana Gas and Citizens Gas relating to PROLIANCE, which provides gas supply management and marketing services to the two utilities. The Petitioners have asked the Commission to determine that Proliance should be a regulated entity.

The Complaint was filed March 29, 1996, under Cause No. 40437 by the Petitioners. PROLIANCE, Indiana Gas and Citizens Gas filed their response on April 16, 1996.

ENRON'S PROPOSAL FOR RATE MAKING CONCERNING STANDARDS OF CONDUCT

Enron Capital & Trade Resources Corporation (ENRON) filed a Petition for Rulemaking on March 29, 1996. In its Petition, ENRON requested that the Commission "institute a proceeding to establish statewide standards of conduct governing the relationship between natural gas local distribution companies (LDCs)... and their marketing affiliates." ENRON noted that the LDCs and their affiliates may have the ability to exert undue market power. ENRON also noted that the FERC and several states have either adopted Standards of Conduct or are considering Standards as a means of providing an environment for fair competition.

The Docket Entry noted that "...the competitive implications of gas marketers affiliated with local distribution companies is a serious matter for this Commission as we contemplate a future with less regulatory scrutiny of LDC activities...proposing a new rule is the prerogative of the Commission."

V. THE STRUCTURE OF THE UNITED STATES NATURAL GAS INDUSTRY

Producers

Gas production in the United States increased from 5,377 quadrillion Btus in 1949 to 19,230 billion quads in 1995 (preliminary estimate).[2] However, the level of gas production in 1995 has been fairly constant since 1967 when 19,068 quads were produced. The high point was reached in 1971 when 22,280 quads were produced. It should also be noted that imports of natural gas, primarily from Canada, have augmented production of gas in the United States. Imports have risen from .58 quads in 1967 to 2.80 quads in 1995 (preliminary).[3] The vast majority of all gas is produced by 272,000 natural gas wells.

Storage Facilities

As of 1992, there were more than 400 underground gas storage facilities in 27 states and Canada. These facilities have the capability of holding more than 3 quads of gas for withdrawal when the gas is needed. In this regard, Indiana is one of the leading states.[4]

Pipelines

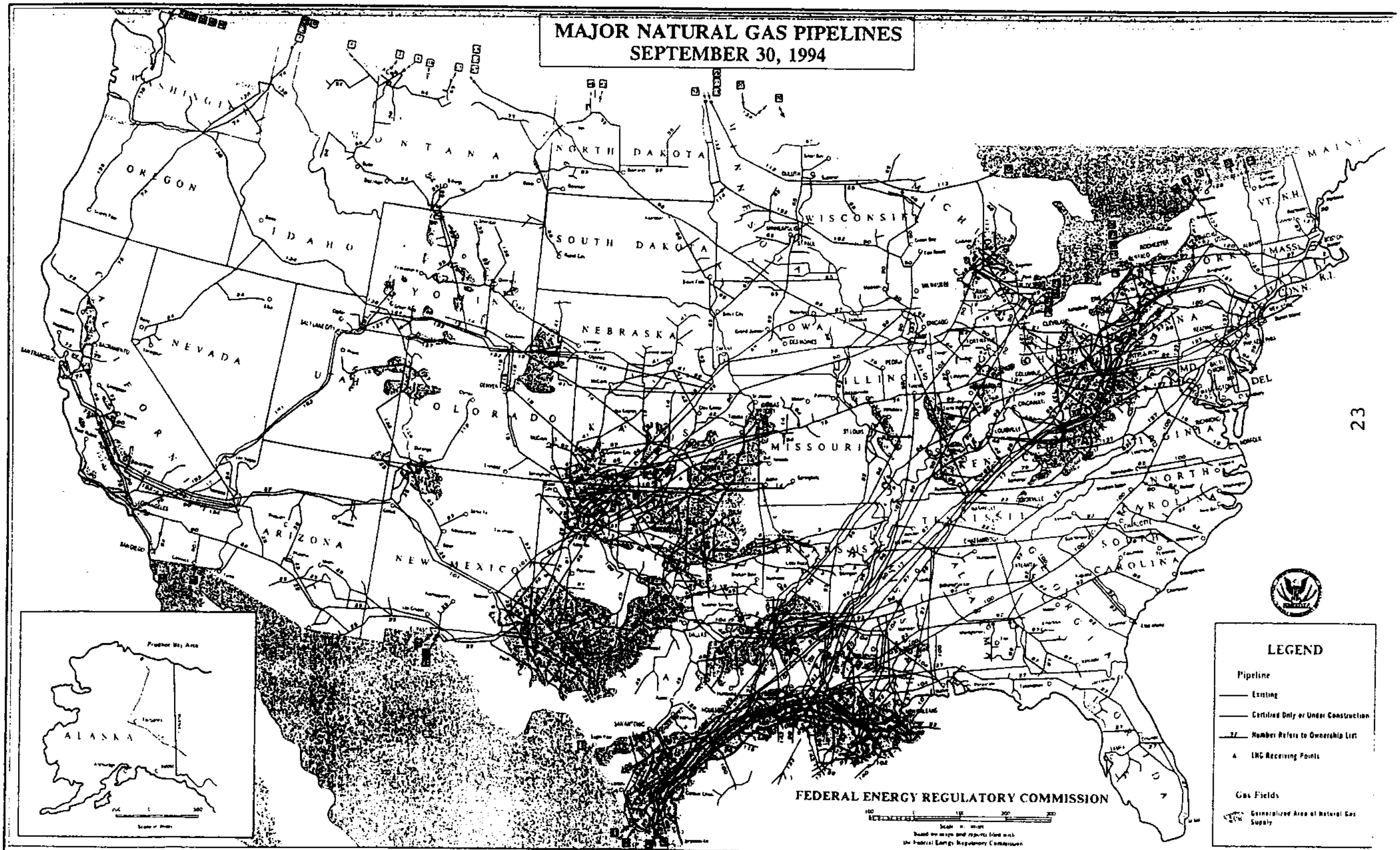
There are about 32 pipelines in the United States that deliver about 87% of all gas[5] through some 1.2 million miles of buried pipe. There are more than 11,000 miles of additional Interstate and intra-state natural gas pipelines under construction (or recently completed). These additional pipelines will have the ability to carry 25 billion cubic feet of additional gas per day.[6] (See next page for a map of pipelines.)

Local Distribution Companies (LDCs)

There are about 2000 natural gas entities involved in the distribution of natural gas. There are about 1000 Investor-Owned Local Distribution (IOU) Companies. The 10 largest investor-owned LDCs account for about 20% of gas deliveries to customers. There are about 1000 Publicly-Owned (e.g., municipal) Local Distribution Companies, marketers, brokers and aggregators. According to the American Public Gas Association, there were 950 municipal, county or public utility district gas systems in the United States in 1995 serving 3.8 million customers. **95% are served by a single pipeline.**

Marketeers, Brokers and Aggregators

With the sharp rise in transportation gas resulting from federal law and regulatory policy, several firms were organized to sell gas to shippers (primarily LDCs and industrial customers). These firms (e.g., ENRON) will

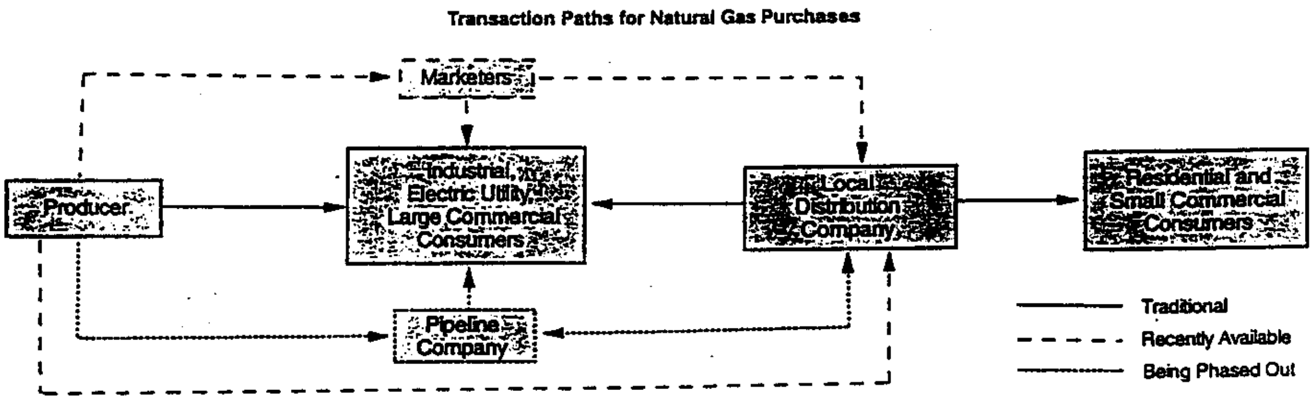

MAJOR NATURAL GAS PIPELINES
SEPTEMBER 30, 1994
FEDERAL ENERGY REGULATORY COMMISSION
LEGEND
Pipeline
Existing
Certified Only or Under Construction
Number Refers to Ownership List
LNG Receiving Points
Gas Fields
Generalized Area of Natural Gas Supply
ALASKA
Prudhoe Bay Area
WASHINGTON
OREGON
IDAHO
MONTANA
NORTH DAKOTA
SOUTH DAKOTA
NEBRASKA
NEVADA
UTAH
COLORADO
ARIZONA
NEW MEXICO
KANSAS
MISSOURI
IOWA
ILLINOIS
WISCONSIN
ARKANSAS
TENNESSEE
NORTH CAROLINA
SOUTH CAROLINA
VT.
N.H.
MASS.
CONN.
R.I.
DEL
MD
MAINE

provide a bundle of services that are tailored to meet the unique needs of its clients. Most large industrial customers have the expertise and the financial incentive to take an active role in their gas procurement. Smaller LDCs, in contrast, may prefer to have a gas marketer to "rebundle" many of the services.

The following graph illustrates the changing structure of the natural gas industry.

GRAPH 5

CHANGING STRUCTURE OF THE NATURAL GAS INDUSTRY



VI. CURRENT REGULATORY REQUIREMENTS OF INDIANA GAS UTILITIES

A. Rate-of-Return Regulation

Prior to recent regulatory changes, such as the passing of Senate Enrolled Act 637, Indiana ratemaking procedure has remained basically unchanged since enactment of the Public Service Commission law of 1913.[7] Utilities are required to charge rates which are reasonable and just based upon the fair value of their property used and useful as determined by the IURC. Schedules of all rates must be filed with the IURC and thereafter no change in any schedule shall be approved by the IURC, except that a decrease may be made upon less than 30 days notice.[8] The Indiana Supreme Court summarized the IURC's charge as:

> *[I]nvolves a balancing of all these factors and probably others; the balancing of the owners' or investors' interest with the consumers' interest. On the one side, the rates may not be so low as to confiscate the investors' interest or property; on the other side rates may not be so high as to injure the consumer by charging exorbitant prices for service and at the same time giving the utility owner an unreasonable or excessive profit.*[9]

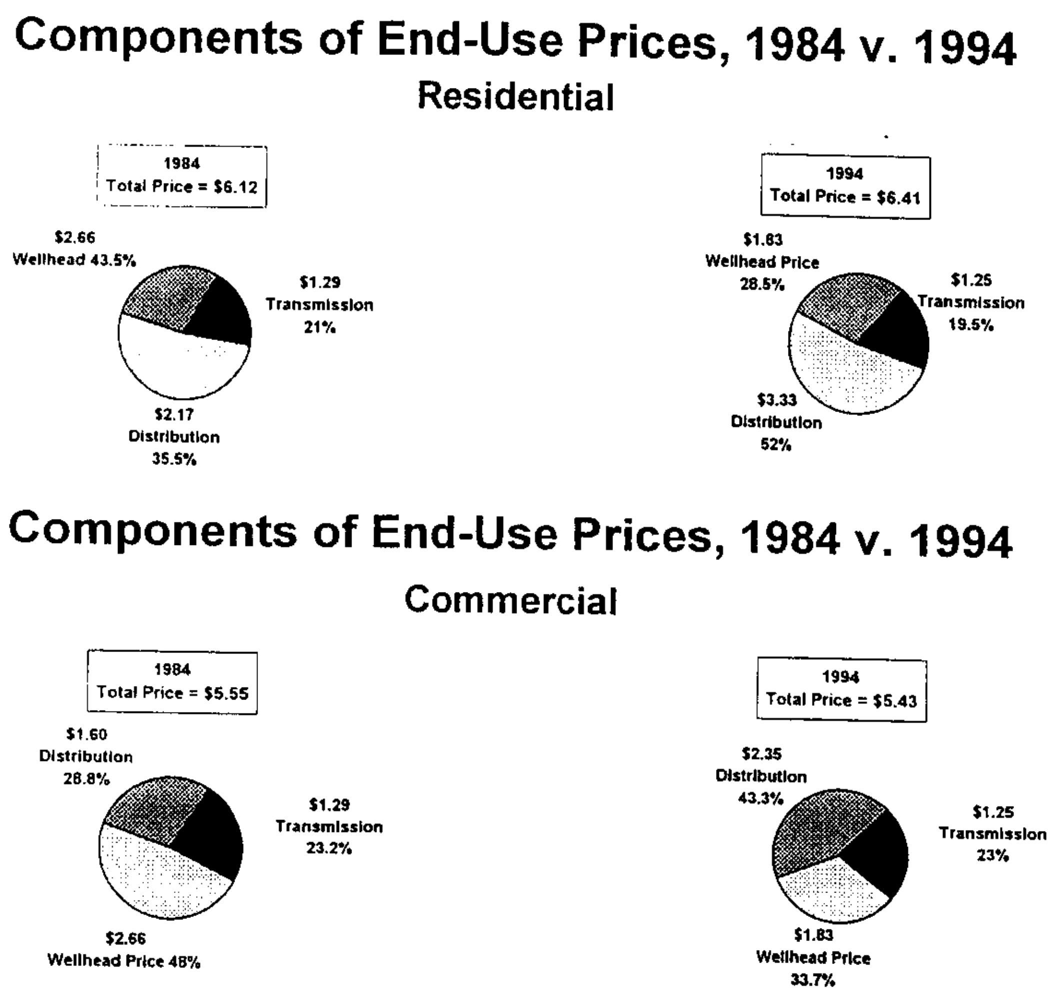
Indiana is one of only five states that continue to recognize "fair value" in any form.[10] Most states rely on "original cost" to determine the ratebase.

Historically, the IURC has attempted to fix utility rates, in general rate case hearings, on a basis which could be reasonably expected to endure for approximately three years. During the interim, a utility would absorb any cost increases to the benefit of ratepayers. The utility should also benefit in the meantime from increased sales, savings through growth, technological advances, and other factors. In addition, the IURC has granted interim rate relief to certain gas distribution utilities through emergency or supplemental hearings in which only the increased cost of gas to the utility was considered.[11] This relief is known as the Gas Cost Adjustment (GCA).

B. The Gas Cost Adjustment Clause

The three year lag between cases became untenable during the era of Arab oil embargoes of the 1970s. The Federal Power Commission enacted, as a result of the volatility of gas prices and the fact that gas costs constituted most of the pipeline's cost, automatic pass-through clauses (PGAs-purchased gas adjustment clauses) that allowed pipelines to pass on to LDCs the increased cost of gas after a perfunctory review by the FPC. The following graph illustrates the relative importance of natural gas to the residential and commercial customers' total bills. The graphs also point out that the relative importance of the commodity costs has declined after the effects of the oil embargoes dissipated and de-regulation of wellhead prices began to take effect.

GRAPH 6



Source: Energy Information Administration

Provided by ENRON

Using the four largest Indiana utilities as examples, gas costs averaged about 57% of an LDC's total costs in 1995. Following the lead of the FPC, most state commissions believed that it was necessary to insulate the LDCs against some of the financial risks that were beyond the control of the LDC. The Indiana Commission, like most state commissions, instituted pass-through mechanisms. Indiana's Purchase Gas Adjustment clause (PGA) allowed LDCs to pass on the increased cost of gas, from their pipeline suppliers as required by the FPC's PGA, to the LDCs' retail customers. The Indiana PGA was handled without hearings in a simple and quick manner without reconciliation or a "return" test (Commission Order 12/11/1970). This simple PGA did protect the LDC's investors during periods of rapid increases in gas costs. Correspondingly, during periods of declining gas costs, the PGA enabled customers to realize the benefits in a timely manner. The automatic pass-through of gas costs also reduced the number of rate cases that often resulted in "pancaking" (where a LDC would have more than one case pending at the same time). In the IURC's current version of the GCA, the "base cost of gas" is determined by the Indiana Commission and remains fixed between rate cases. The difference between the current cost of gas and the base cost of gas is the basis for the GCA. The GCA is sometimes referred to as a "tracker."

Over the course of approximately twelve years, as many as eight distinct types of trackers developed. It was also discovered that the effect of the trackers on consumer bills was more substantial than originally anticipated. For example, in 1982 Indiana Gas Company had a PGA which generated revenue in excess of $42,000,000. The IURC approved the request within 30 days which benefited IGC's shareholders. In contrast, Indiana Gas Company's last case involved a revenue increase of $37,000,000 and required a 7 month adjudication process. Arguably, the customers realized benefits from the delay. In 1983, the Commission initiated an investigation into the existing gas cost adjustment clause with the intention of adopting uniform standards that would expedite the process. During the course of the Commission's investigation, P.L. 43-1983 was signed into law for the purpose of giving the Commission guidance concerning GCAs. P.L. 43-1983 also allowed the utilities to request the pass-through of other costs related to the procurement and use of gas.

In response to a request to change the tracker, the Commission is required to conduct a summary proceeding based solely on the GCA. If the proposed change in the tracker meets the following tests, the Commission is obliged to grant the change [paraphrased from IC 8-1-2-42].

1) The utility has made every reasonable effort to acquire long term gas supplies so as to provide gas to its retail customers at the lowest cost reasonably possible;

2) Prove that the pipeline has filed for its change of cost with a duly constituted regulatory authority (i.e., the FERC);

3) The gas cost adjustment applied for will not result, in the case of a public utility, in its earning a return in excess of the return authorized by the commission in the last proceeding in which the basic rates and charges of the utility were approved, subject to Section 42.3 of this chapter, if the gas cost adjustment applied for will result in the public utility earning a return in excess of the return authorized by the commission in the last proceeding in which basic rates and charges of the gas utility were approved, the gas cost adjustment applied for will be reduced to the point no such excess of return will be earned.

4) The utility's estimate of its prospective average gas costs for each such future recovery period is reasonable and gives effect to:

   a) the actual gas costs experienced by the utility during the latest recovery period,
   b) the actual gas costs recovered by the adjustment of the same recovery period.

5) Should the commission, at any time, determine that an emergency exists that could result in an abnormal charge in gas costs, it may, in order to protect the public or the utility from the adverse effects of such change suspend the above requirements.

Typically, if a petitioning utility uses the GCA procedure, it files on a quarterly basis (semi-annually in a few cases) with a projection of the cost of gas over the next three months (or more). At the end of the succeeding quarter, the variance (over or under recovery) is calculated and the differences between the projected and actual costs are reconciled and recovered over the next 4 quarters. To "flatten out" the seasonal variations in costs, the reconciliation of variances was spread over a 12 month period based on the projected sales for each of the quarters in the 12 month period.

Prior to SB 637, the annual methodology compared the dollar amount of the utility's Net Operating Income (NOI) for the previous 12 months with the dollar amount authorized for NOI in the utility's most recent rate case. If the current dollar amount of NOI exceeds that found to be appropriate in the utility's most recent general rate proceeding, the utility was deemed to have earned an excessive return. Initially, the utility's rates would be reduced by 1/4 of the excess and the full over-earnings would have been made permanent if the over-earnings persisted over the course of a year. SB 637 allows the utility to compare its earnings to the authorized earnings for the previous 5 years or the period since the issuance of its last rate order, which ever is longer. The difference between the determined NOI and the authorized NOI is then calculated for each quarterly application during the relevant period. If the sum of the differentials is less than zero, the GCA is not reduced. However, if the sum of the differentials is greater than zero, then the GCA is reduced by one quarter or the <u>lesser</u> of the sum of the differentials over the relevent period, or the amount by which the return in the current application is more than the authorized return.

THE GAS COST ADJUSTMENT CLAUSE IN OTHER STATES

During recent years, only three state commissions have eliminated the GCA process for all or some of the gas utilities under their jurisdiction. In contrast, twelve states have eliminated fuel adjustment clauses for all or some of the electric utilities under their jurisdiction.[12] As Indiana did several years ago, other state commissions review the continued efficacy of gas adjustment clauses (e.g., Colorado, Connecticut, Michigan, Pennsylvania are considering the elimination of the Purchased Gas Adjustment clause). Still other states have considered proposals to streamline the GCA process by making the purchases of gas tied to market prices (e.g., California). Some states have reviewed GCAs and decided to retain them. The following are typical predicates for review, revision, or elimination of gas cost adjustment clauses by state commissions:

1) The original warrant, the volatility of prices, has not been as much of a concern in recent years.

2) There have been rare instances where some state commissions have found the automatic pass-through clauses had been abused or manipulated by utilities,

3) Automatic pass-through clauses do not provide incentives for the utilities to reduce their gas (fuel) costs. The utility can not retain the benefits if they procure lower cost gas (fuel) and they bear no responsibility if the gas (fuel) costs increase.

4) Automatic adjustment clauses may distort the price signals to customers since the clauses tend to "flatten out" the fluctuations in gas (fuel) prices.

5) Determined to be unconstitutional in certain cases (Vermont).

6) Replaced with performance-based rates.

THE GAS COST ADJUSTMENT CLAUSE IN A COMPETITIVE ENVIRONMENT

In a competitive environment, or even with the adoption of performance-based rates, it seems likely that states and utilityies will reconsider automatic adjustment clauses. In a competitive environment, for example, customers may gravitate to gas suppliers that offer "guaranteed" prices. This was the case in proposals by New Jersey Natural Gas that would allow customers an option of fixing their price of gas based on the 12 month future's market price of gas (Docket GT-96-070524, July 16, 1996). In the event that performance-based rates are adopted, the automatic adjustment clause might be subsumed as one of the indices (e.g., California, Iowa, New York). That is, if the index is the total cost of providing service and the utility beats the index, they receive a reward. If the LDC can not achieve the goal, the shareholders bear some of the risks.

C. Regulation of Investor And Municipal Gas Utilities

The Indiana Utility Regulatory Commission currently regulates 24 LDCs of the 39 utilities that provide gas to Hoosiers. This includes all 20 investor-owned LDCs and 4 municipal LDCs including Citizens Gas & Coke. These 24 LDCs generated more than $1.3 billion in revenue in 1995. It is not unusual for a state regulatory commission to regulate a municipally-owned gas utility. According to the National Association of Regulatory Utility Commissioners, 20 states regulate municipal utilities.[13] A few other states regulate the safety of municipally-owned gas systems and in a couple of states there are no municipal gas utilities.

D. Pricing Flexibility

The IURC has allowed gas utilities substantial pricing flexibility. Primarily, utilities have asked for the ability to offer lower rates as a means of attracting or retaining large customers and preventing economic by-pass. The IURC has approved economic development tariffs for large and small LDCs on a case-by-case basis through a general (full) rate case or part of the thirty-day filing process.[1] As a result, most LDCs offer firm and interruptible transportation as well as unbundled services such as: balancing, storage and backup supply.

Currently, no LDC in Indiana is offering unbundled services for residential or small commercial customers. Nor have any experiments been

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[1] The 30 day filing process is authorized by IC 8-1-2-42(a) which provides the Commission with at least 30 days before a change in tariffed rates can be made. The Commission has processed 146 such cases since 1982. Most of the requests for expedited IURC review were following FERC actions in 1983 (FERC Order 319 providing for special marketing programs that allowed pipelines to sell off-system and blanket certificates) and 1986 (FERC Order 436 which gave industrial and LDCs the same access to pipeline transportation services).

undertaken. Moreover, no gas utility has filed a case that provides for increased pricing flexibility for any customers under IC 8-1-2.5-9.[2] According to former IURC Commissioner Fred Corban (A speech entitled Unbundling Behind the City Gate Executive Enterprise Institute October 1995):

> ...[T]he existence of new flexibility in law may have little impact on what really happens in the market place despite our best desires. Fifteen years ago, there was a considerable controversy over whether natural gas customers should be provided transportation on their LDC system. In Indiana this was a long and bitterly fought battle on a number of systems.
>
> As a result, a statute was passed which allowed the single customer to request a transportation tariff...Despite this, no one has ever filed a case requesting a transportation tariff under the statute which was passed in 1987.

---

[2] Southern Indiana Gas & Electric Company withdrew their proposal and a proposal by Northern Indiana Public Service Company has not been considered by the IURC.

In the aftermath of the Supreme Court Decisions, the Congress received numerous complaints by consumers, distributors and producers (they complained that the pipelines were exercising monopsony power-one buyer and numerous sellers) that the deregulated pipelines were engaging in a variety of discriminatory and abusive practices. Congress authorized the Federal Trade Commission to review the situation and prepare a report. The FTC completed its report in 1935[15] and concluded that the pipelines had been engaging in uncompetitive and abusive practices.

In response to the FTC Report, Congress authorized the Federal Power Commission (FPC) to treat natural gas pipelines as "common carriers" similar to the approach they adopted for oil pipelines in 1906. As common carriers, pipelines were required to provide equal access to their facilities to all parties. Congress intended that thousands of natural gas producers would be able to sell to hundreds of local gas distribution companies and, thereby, create a competitive natural gas market.

Pipelines objected to competition and sought a more intrusive regulatory policy that would protect them from competitive forces. Congress obliged by enacting the Natural Gas Act in 1938. Congress also intended to resolve the federal and state jurisdictional issues that emanated from the Supreme Court's Decisions in the 1920s and to protect consumers from the monopoly abuses of the pipelines. The NGA authorized the FPC to regulate:

1) sales for resale in interstate commerce,
2) transportation of gas in interstate commerce, and
3) facilities used for such sales and transportation.

As a result, the NGA protected monopoly pipelines by conferring broad authorities on the FPC. By way of examples: A) The NGA required the FPC to restrict the construction of new pipelines until there was a clear finding that they were "required in the public interest." B) Pipelines were not obligated to provide access to their bottleneck facilities. The United States Supreme Court, in an historical reference to this era said pipelines were permitted to act as "tollgate(s) lying athwart a trade rate"[16] preempting beneficial transactions between producers and consumers.

The FPC used its NGA powers to correct another abuse of monopoly power related to self dealing between the pipeline and its affiliates. The FPC was concerned that unregulated affiliates of the monopoly pipelines might charge the parent pipeline excessive prices for goods and services. These excessive prices would, then, be passed on to customers by the regulated pipeline as a normal cost of doing business. The concerns were well founded. The Congress had recently passed the Public Utility Holding Company Act to prevent future abuses by holding companies.[17] The U.S. Supreme Court affirmed the FPC's authority to regulate transactions between affiliates in *Interstate Natural Gas Co vs. FPC* 331 U.S. 682 (1947). In this case, the FPC felt obliged to regulate the prices of gas that Interstate Natural Gas was buying from its affiliates.

In 1954, the Supreme Court held in *Phillips Petroleum Co vs. Wisconsin* 347 U.S. 672 (1954) that the NGA obligated the FPC to regulate independent producer sales to interstate pipelines. Congress, in 1955, recognized that the regulation of independent producers would thwart their intention of having a competition at the wellhead and passed legislation to exempt independent producers from FPC regulation. President Dwight D. Eisenhower vetoed legislation that would have exempted independent gas producers from FPC regulation.

To comply with the Supreme Court's ruling in Phillips, the FPC attempted to regulate both affiliate and independent producers by using a traditional cost-of-service framework. By 1960, the FERC had abandoned the effort as administratively unworkable (the FERC had only decided 10 cases and had a backlog of 2900 pending cases).

In 1961, the FERC adopted the "area rate" approach that divided the producing states into several areas and setting price ceilings (based on the average cost of finding and producing gas) for all gas produced in those areas. While the administration of area rates was preferable to the producer-by-producer method, it still required about 10 years to determine each areas rates. As a result, the FPC granted "interim" rates. The FPC, in a effort to give recognition to the cost of new wells versus established gas wells, established a system of "vintage" pricing that allowed higher ceiling prices on new gas relative to old gas. The FPC also refused to certify any new producer until they could demonstrate that they were within the bounds of the interim rate. In periods where the cost of new gas exceeded the historic average and the ceiling price for new gas, producers would either not bring in new gas wells or would sell the gas in the intrastate market.

During the 1970s, when there were concerns about adequate supplies of gas in the upper midwest and northeast, producing states had an adequate supply of reasonably priced gas. This provided inducements to gas intensive firms to leave the "rust belt" and move to gas producing states. In periods where the price of bringing in a new gas well was less than the historical average, the FPC's ceiling price overstated the cost of gas by implicitly assuming that new gas was always more expensive than vintage gas. A perverse result was that consumers in Boston, for example, could purchase gas cheaper than consumers in Texas.

The Arab (OPEC) oil embargoes of the 1970s combined with the FPC's regulation of producer prices contributed to the perception, if not the fact, that natural gas was in very short supply. As a consequence, the price of natural gas increased dramatically.

TABLE 10
WELLHEAD PRICE

	Nominal Price/MCF	Real Price/MCF	
1970	0.17	0.56	
1971	0.18	0.56	
1972	0.19	0.57	
1973	0.22	0.62	
1974	0.30	0.78	- 1st Arab Oil Embargo
1975	0.44	1.04	
1976	0.58	1.30	
1977	0.79	1.67	
1978	0.91	1.78	- 2nd Arab Oil Embargo

Real = Chained 1992 dollars calculated using GDP implicit price deflators.
Source: U.S. Depart of Energy/Energy Information Administration "Annual Energy Review 1995" July 1996 pg. 203

The NGPA and the FPC's regulation of natural gas production created a situation where the regulated price of "new" gas exceeded estimates of the market cost of gas. The intent of the FPC was to encourage the exploration for and the production of new gas as well as prevent gas producers with older gas from obtaining excess profits. Simultaneously, the existence of a large surplus of gas that was shut in by the FPC's vintage pricing ("old" gas) regulations, had driven a number of producers into bankruptcy. During this period, interstate pipelines incurred take-or-pay obligations of $11.7 billion for gas that they could not economically market.[18]

The sharp increases in gas costs and concerns for adequate supplies served as a catalyst for Congressional and regulatory actions. In 1978, a wide array of energy legislation was passed, including:

- The Public Utility Regulatory Policies Act of 1978 (PURPA),
- The National Energy Conservation Policy Act,
- The Natural Gas Policy Act (NGPA), and
- The Power Plant Fuel Use Act (FUA)

These Congressional actions were passed in response to the Department of Energy (and other experts) reports that forecast imminent shortages of natural gas. The Power Plant Fuel Use Act, for example, contained a requirement for electric utilities and industrial customers to curtail their use of natural gas by 1990. The Fuel Use Act contributed to the construction of nuclear and coal-fired units throughout the United States. In many cases, these coal and nuclear units were the subject of "prudence" investigations for cost overruns and excess generating capacity. Currently, many of these same generating units are the subject of "stranded cost" concerns for electric utilities. It's also noteworthy that there were moratoriums on the connection of new gas customers which led to uneconomic use of certain energy uses such as electricity for resistance heating.

TABLE 11
WELLHEAD PRICE

	Nominal Price/MCF	Real Price/MCF	
1979	1.18	2.13	- NGPA (e.g., partial de-regulation by '85)
1980	1.59	2.63	
1981	1.98	3.00	
1982	2.46	3.51	
1983	2.59	3.54	
1984	2.66	3.50	
1985	2.51	3.20	- Orders 380 and 436
1986	1.94	2.41	
1987	1.67	2.01	- Fuel Use Act Repealed (ending restrictions on using gas for powerplant & industrial use and incremental pricing) FERC Order 500
1988	1.69	1.96	
1989	1.69	1.88	- Natural Gas Wellhead Decontrol Act

Source: U.S. Depart of Energy/Energy Information Administration "Annual Energy Review 1995" July 1996 pg. 203

Another attendant effect of increased natural gas prices, and energy prices generally, was the increased attention to conservation (the PURPA had specific requirements in this regard). Coincidentally, many of the most energy intensive industries were having to substantially revamp their operations to switch fuels and, in general, be more energy efficient. In some instances, most notably the "rust-belt" industries could not adapt quickly enough and did not survive. These factors, combined with the inability to extend service to new customers, contributed to a diminution of the markets for natural gas. At a time when natural gas markets were contracting, the federal government was exerting considerable efforts to expand supplies of natural gas. In addition to efforts to stimulate domestic production of natural gas, imports of natural gas from Canada and Liquid Natural Gas (LNG) from Algeria were increased. The Department of Energy and consortiums of private firms also planned to construct synthetic natural gas and coal gasification facilities.

TABLE 12
NATURAL GAS PRODUCTION + IMPORTS IN RELATION TO DEMAND & WELLHEAD PRICE
(Quadrillion Btu and Real Price per MCF)

	Domestic Product	Import	Total	Demand	Price		Domestic Product	Import	Total	Demand	Price
1980	19.91	1.01	20.92	19.88	2.63	**1985**	16.98	.95	17.93	17.28	3.20
1981	19.70	.92	20.62	19.40	3.00	**1986**	16.54	.75	17.29	16.22	2.41
1982	18.32	.95	19.27	18.00	3.51	**1987**	17.14	.99	18.13	17.21	2.01
1983	16.54	.94	17.48	17.83	3.54	**1988**	17.60	1.30	18.90	18.03	1.96
1984	18.01	.85	18.86	17.95	3.50	**1989**	17.85	1.39	19.24	18.80	1.88

Source: United States Department of Energy/Energy Information Administration Annual Energy Review 1995

In the 1980s, despite moderating gas prices, it was a legacy of extraordinary price increases and evidence of a huge "gas bubble" that caused Congress to lose faith in the ability of the FERC to regulate producer prices. The Congress enacted the Natural Gas Policy Act in 1979 that lifted the fuel use act prohibitions against gas usage. Section 601 of the NGPA initiated the process of "well head de-control", Section 311 of the NGPA broke down existing lines of demarcation between interstate and intrastate markets for natural gas. In response to the NGPA, the FERC initiated a series of Rulemakings, beginning with Order 436 in 1985, to reduce regulation of the natural gas markets for those segments that were competitive (e.g., production of natural gas). The combined effects of the NGPA and Order 436 were to fundamentally change the natural gas industry. The fundamental change was accomplished by, first, pricing natural gas as a commodity - no longer subject to the FERC's rate review. Secondly, the transportation and sale of natural gas became distinct services.

By the end of the 1980s, the FERC's policies, combined with moderating prices of energy on a world wide bases, contributed to sharp reductions in the wellhead price of natural gas. In response to changes in federal policy and a national economic recovery, demand for natural gas also began to increase.

TABLE 13
WELLHEAD PRICE

	Nominal Price/MCF	Real Price/MCF	
1984	**2.66**	**3.50**	**(Highest Price Level)**
1990	1.71	1.83	
1991	1.64	1.69	
1992	1.74	1.74	- Energy Policy Act & FERC Order 636 (effective Nov 1993)
1993	2.04	1.99	
1994	1.88	1.79	
1995(E)	1.59	1.48	

(E) = Estimated
Source: U.S. Depart of Energy/Energy Information Administration "Annual Energy Review 1995" July 1996 pg. 203

The Modern Era - Energy Policy Act of 1992 and FERC's Response

From the perspective of the gas industry, the EPAct was enacted against Iraq's invasion of Kuwait, the threat to Saudi Arabia (producing 5.5 million barrels per day which is more than 1/4 of total daily U.S. usage), the ensuing Gulf War and the UN embargo of Iraq. The embargo of Iraq's oil removed 2.5 million barrels per day from the World's markets. The embargo, combined with the uncertainty, drove-up the price of oil and all other substitute fuels such as natural gas. The volatility of prices during the Gulf War were reminders of the aftermath of the two Arab oil embargoes. These fears exacerbated the traditional mind-set of local distribution companies that long-term gas supply and transportation contracts (e.g., 20-40 years) were essential to providing reliable and relatively low-cost gas.[19]

FERC's Order 636, issued in April 1992, was an attempt to remedy decades of poorly placed attempts to regulate the United States production of natural gas. The fact that the FERC had no influence over world markets for energy, contributed to the inefficiency of gas markets. By the time FERC issued Order 636, the FERC's previous orders (e.g., Order 436) provided customers such as LDC's to de-contract from certain long-term and uneconomic contracts.

As customers "de-contracted" gas supply, excess supply emerged. Producers sold large volumes of de-contracted gas to marketing companies at very low prices. The FERC also allowed special marketing programs (SMPs) to allow producers to sell this released gas. While these programs were ultimately struck down by the courts as being unduly discriminatory in favor of larger customers at the expense of smaller customers, it also set the stage for pipelines to serve as the transporting agent for others.

As with gas supply, the local distribution companies and other end-use customers typically had long-term contracts with pipelines. As customers de-contracted pipeline capacity, a growing surplus of transportation capacity also emerged. To compensate the pipelines for this new excess pipeline capacity, the FERC approved proposals to allocate portions of these stranded costs to remaining customers, departing customers and shareholders.[20] The allocation of these "stranded costs", combined with FERC's adoption of "Straight Fixed Variable" rates, resulted in substantial additional costs to LDCs that contributed to the uneven distribution of benefits associated with a more competitive natural gas industry.

As early as 1991, some of the initial market responses were already noticeable. The national average wellhead price, for example, dropped to $1.64 per Mcf (over a 27% decline from 1984 levels). In real terms (adjusted for inflation) the price of natural gas at the wellhead dropped by 51% between 1983 (the highest price) and 1994. There are other notable perspectives on the decline in natural gas prices. For example, between 1987 and 1995 gas transmission and wellhead costs have fallen by about the same percentages (26.5% from $2.64 to $1.94/mmBtu in real 1996 dollars for transportation and 26.4% from $2.16 to $1.59/mmBtu for wellhead gas). The EIA noted, however, that there were no declines in distribution costs. As the graphs depicted at the outset, these price reductions have been shared unevenly among the various types of customers. The following table reiterates the historical price changes.

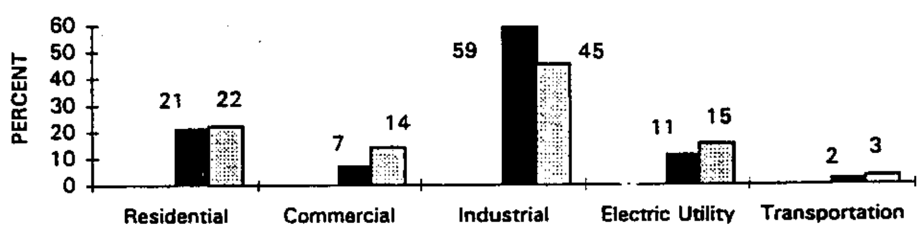
Residential customers saw a 11% decrease
Commercial customers saw a 15.2% decrease
Industrial customers saw a 54.9% decrease
Electric Utilities saw a 50.6% decrease

Despite these price declines, by 1994 residential and commercial use of natural gas just equaled the 1972 usage. By 1994 industrial use had increased back to the 1972 levels. It's interesting to note that the percentage of total gas consumed has declined for industrial customers since 1950.

GRAPH 7

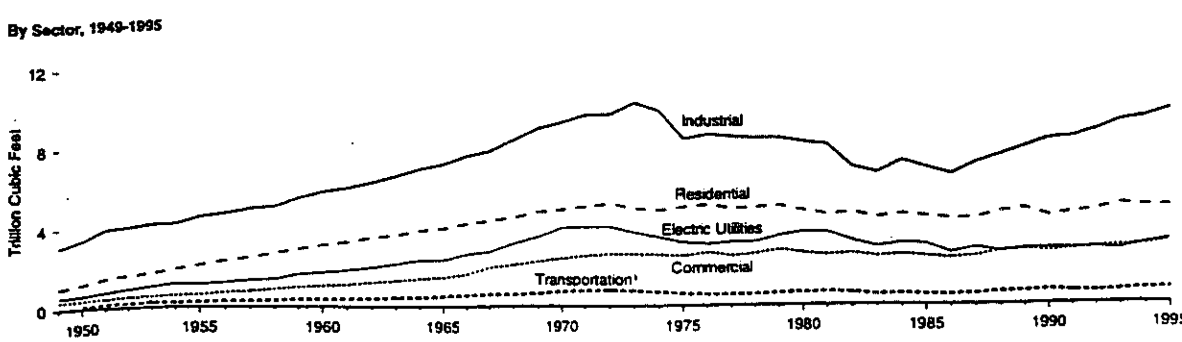
NATURAL GAS USE BY CLASS

PERCENT OF GAS CONSUMED BY DIFFERENT CUSTOMER CLASSES FROM 1950 TO 1995



GRAPH 8

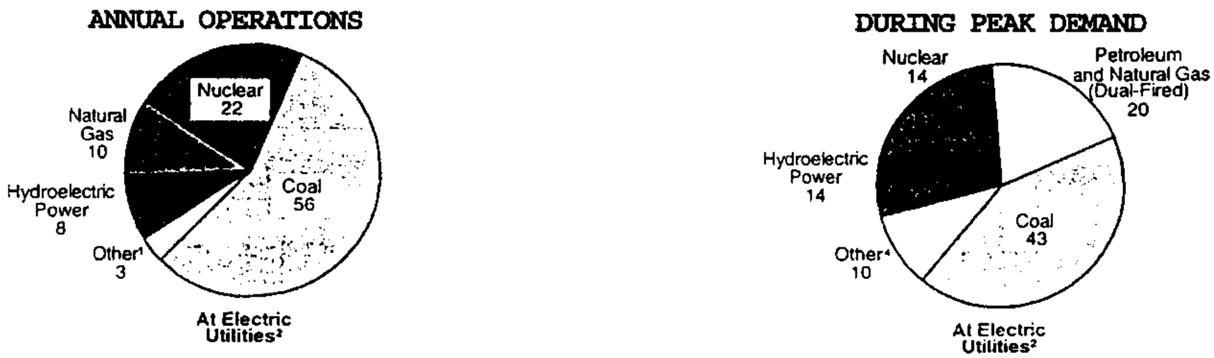
NATURAL GAS USE BY CLASS 1950 - 1995



As the price of gas declined, gas became increasing competitive with coal as an electric generating fuel. The gas price declines, combined with technology improvements to gas-fired generating units such as "Advanced Combined Cycle Gas Turbines" that use innovative jet airline technology are expected to improve efficiencies from a current level of 40% to as much as 65%.[21] Compared to the costs associated with constructing coal or nuclear units, gas units are lower cost. Gas units also require less time to construct. As a result, Gas' share of the electric generating market increased from 10.1% in 1986 to 10.4% in 1995 despite a 39% drop in the price of coal during the same period.

GRAPH 9

ELECTRIC UTILITY USE OF NATURAL GAS



It's important to note that of the 3 trillion kWh generated in 1995 coal accounted for 55.2%. In sum, the declines in the price of gas and coal have been a significant factor in the 7.2% decline in the real cost of electricity from 1975 through 1995.[22]

Declines in the cost of electricity, combined with the increasing efforts by the federal and state governments to instill competition in the electric utility industry, have put pressure on gas utilities to keep their costs down. This pressure on gas utilities is likely to intensify over the next few years. Independent assessments by CINergy and the State Utility Forecasting Group suggest that the price of wholesale power could drop in excess of 50%. This seems to be consistent with the FERC's estimates of $3.8 to $5.4 billion dollars per year in expected savings from wholesale competition. One effect of the decline in electric prices will be that gas utilities may not be able to increase their market share of "marginal" end-uses of natural gas relative to the electric industry. An analysis by R. J. Rudden Associates [23] noted:

The results of the study generally show that under full electric industry open access and competition, natural gas has the potential to lose a significant portion of its price advantage during the winter in all regions and market segments...Depending upon the market segment and geographic region analyzed, the competitive price advantage for natural gas in the winter could decline by *between 26 and 72 percent...The competitive price advantage could decline by 48% for the residential market, 46% for the commercial market and 41% for the industrial market.*

Even demand for gas for use as an electric generating fuel is not likely to grow substantially in the next few years due to excess baseload coal and nuclear generating units. That is, to the extent that better coordination of generating capacity is an outgrowth of competition within the electric power industry, there will be a maximization of the use of more economical coal-fired and nuclear baseload capacity in preference to gas-fired capacity. According to the EIA, coal-fired units have been running at a 60-65% annual capacity factor. Nuclear capacity achieved an annual capacity factor of 78% in 1995.[24]

Open-access will flood the market with billions of kilowatt hours of cheap -2¢to 3¢ per kWh -power from expanded use of...coal plants...In comparison, the cost of power from new combined-cycle gas plants is 4¢ to 6¢/kWh.[25]

To the extent that gas utilities are unable to significantly expand the demand for gas beyond keeping pace with population increases, there is little external pressure to increase prices. The lack of external pressure to increase gas use would occur if some or all of the following conditions are satisfied:

- price of competing fuels (particularly electricity)
- greater efficiency of gas end-uses
- additional gas imports from Canada
- normal weather conditions
- relatively low rates of inflation

VIII. EMERGING ISSUES IN THE NATURAL GAS INDUSTRY

This section will discuss some of the issues that are confronting the natural gas industry, gas customers and regulatory commissions. While there are important similarities in the issues confronting gas and electric utilities, the following discussion addresses the concerns from the perspective of the natural gas industry:

- "Unbundling" of natural gas services at the retail level.
- Retail Competition in the United States and Canada
- "Codes of Conduct" to assure fair competition
- "Stranded Costs" in the natural gas industry
- "Performance-Based" (Incentive or PBRs) Rates
- Reliability including subscription to pipeline and storage facilities
- Gas planning and Demand-Side Management

A. Unbundling Natural Gas Prices

Just as wellhead deregulation stimulated wholesale competition that resulted in lower prices for gas so, too, is there an expectation that extending competition to the retail level would be beneficial. Industrial customers have availed themselves to LDC transportation programs that have allowed them access to lower cost gas. Is it possible to expand retail competition so that residential and commercial customers can benefit? Put another way, why should only large customers have the right?

Opponents of extending unbundling and competition to retail customers have argued that the advantages for residential and small commercial customers are not as clear-cut as the advantages obtained by industrial customers. Even if "aggregators" spring-up, some have questioned whether they can purchase gas cheaper than the LDC. Even if an LDC's competitor can purchase gas cheaper than the LDC, is the supply of gas sufficiently reliable?

It should be recognized that any incumbent LDC will have some of the following significant competitive advantages during the initial stages of competition:

- Access to consumers, billing data and other customer data bases
- Monopoly control over the operation of the distribution system
- Name Recognition and the natural reluctance of most customers to switch
- Familiarity with the Regulatory Commission
- Rights of way

Unbundling of services, provides a means for mitigating some of these endemic advantages of incumbency.

Definition of Unbundling

In its simplest form, unbundling entails the separation of specific services into various components. In the gas industry, service unbundling can involve separation of the LDC's functions into some of the following disaggregated services:

- retail distribution
- arranging pipeline transportation
- arranging storage
- gas procurement
- balancing services
- provide financial instruments to "hedge"
- load forecasting and nominations
- on-system peaking
- back-up services and interruption insurance
- metering, accounting, billing
- maintenance contracts

A customer could purchase each of these unique services separately or purchase "rebundled" combinations of these services. The computer industry has been mentioned as a successful example of unbundling. That is, you can buy a bundled system (including the Personal Computer, Fax/Modem, Printer, monitor, mouse/joystick, software) or buy the computer hardware and software piece-meal.

Benefits vs. Costs of Unbundling

For unbundling and attendant competition to constitute good public policy, the benefits of unbundling have to exceed the costs. Quantifying those benefits are, however, difficult. Even with well-designed experiments, some of the benefits and costs may not be realized during the experimental time period. In California, for example, the Public Utility Commission believes that the local distribution companies are becoming increasingly efficient as a result of competition from alternative gas suppliers. Demonstrating a causal link between competitive pressure on an LDC and an LDC's efficiency is difficult and may not be noticeable until sometime after the experiment (e.g., due to renegotiation of contracts, customer understanding of competition).

To evaluate the benefits and costs, there are several criteria that need to be objectively assessed. These criteria include, but are not limited to:

1) Prices paid by customers in the short and long run,
2) The number and types of customers that choose to participate,
3) The market share of the different competitors over time,
4) The ramifications for reliability in the near and long term.

The Benefits of Unbundling

Certainly, lower prices are the primary objective of efforts to encourage competition. With regard to the benefits of unbundling and an intensely competitive natural gas marketplace flow from the ability of customers to tailor their services to meet their unique needs. That is to say, some customers desire high reliability and are willing to pay for it. Other customers may be willing to have lower reliability (e.g., interruptible or DSM) in exchange for lower prices. Specifically, advocates claim that unbundling results in better price signals so that customers pay the costs that they impose on the supplier. Better price signals are essential to produce an efficient market. Also, to the extent that prices accurately reflect, the unique costs imposed by each customer, "cross-subsidization" concerns are reduced so equity is better achieved.

(1) Accurate price signals ensure services are better matched to each consumer's preference. A monopoly LDC can not produce an "optimal" bundle of services to meet each customer's needs. Certainly, the industrial customers that arrange their own supply discovered that unbundling revealed that some services were mis-priced in the aggregate or un-needed. This suggests that some services were subsidizing other services (if not subsidization of one class by another) and that some services could be more efficiently provided by competitors to the LDCs.

(2) Equitable price signals result from accurate pricing. Cross-subsidization is mitigated because a competitive unbundled market will not abide subsidization.

(3) Efficient price signals are a by-product of accurate and equitable pricing. That is, the pricing encourages customers to use energy efficiently. Given appropriate price signals, customers can decide what energy source, conservation measures or other DSM programs are most appropriate to their unique needs.

(4) Accurate, equitable and efficient pricing provides more reliable information concerning customer response to the gas suppliers. This should result in better decision-making in the planning, contracting, construction and operations of their gas supply portfolios and systems.

(5) Better regulation is also a reasonable expectation in a competitive unbundled environment. Most regulators understand that regulation can, at best, come close to the result of a <u>competitive</u> market. If there is intense competition (e.g., several reasonably comparable competitors providing the same

range of services), state regulatory commissions could relax their oversight of the suppliers gas procurement practices.

The Costs of Unbundling

If customer savings in the short and long run are used as the primary objective criterion, they need to be evaluated in the context of any additional costs that result from unbundling. Billing and administrative costs, stranded costs, system planning and maintaining reliability, the costs of serving lower-load factor customers and the loss of economies of scale are among the additional costs that are often mentioned.

(1) **Billing and Administrative costs** must be segregated so that any additional costs imposed by a customer that wants to change suppliers can be identified. At present, customers that take bundled service from their LDC already pay metering costs, administrative costs, access fees, the cost of gas, the costs of transporting the gas to the burner tip, the cost associated with reliability and etc. As a result, the National Regulatory Research Institute concluded:

> *The additional billing costs of a residential customer choosing unbundled service is quite small. The information on the customer's selection can be electronically transmitted by the new merchant to the distributor. The distributor must perform a one time electronic check against the customer's past usage pattern, and have a computer program that inserts the merchant's name and prices when printing the traditional monthly bill.*

As competition between gas and electric providers increase, gas utilities may find it is necessary to have more sophisticated metering that bills customers based on their time of use and their unique contributions to peak demand.[3]

(2) **Stranded Costs** in the gas industry may increase as a result of unbundling and competition in the gas industry. As in the electric industry, stranded costs often arise from excess capability. Many LDCs, in anticipation of retail competition, have reduced their reliance on longer term contracts. As more customers leave an LDC, in favor of alternative suppliers, the problem of under-utilized elements of an LDC's portfolio will be exacerbated.

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[3] Several gas utilities have begun to install "automatic meter reading" (AMR). By way of examples, Commonwealth Gas (Cambridge, Mass) installed 150,000 meters. (GAS INDUSTRIES May 1995), The President of CGCo said: "*There is nothing more basic than being able to obtain accurate and timely meter readings*". Public Service Company of Colorado, in an effort to reduce its meter reading costs and improve the meter reading accuracy to 99.9%, began installing 330,000 AMRs in 1995. PSCo said that AMR is cost effective in 80% of all cases (Gas Research Institute March/April 1995.

(3) **System Planning and Reliability** for the distribution system will continue to be the responsibility for the planning, physical operation, maintenance, & the reliability of the system. Among other things, the distributor will have to make sure that the alternative suppliers are "in balance" (supply = customer demand). To the extent that imbalances occur, the penalties should serve two functions: a) to compensate the distributor and b) to send a signal to the supplier to do a better job of forecasting customer demand and procuring adequate supplies of gas.

(4) **Low-Load Factor Customers** may be more expensive to serve. Opponents of unbundling have asserted that low load factor customers (i.e., customers that have relatively high peak demand and lower average use in a period) are more expensive to serve than high load factor customers (e.g., industrial customers with relatively constant usage). It may be, for example, that an alternative provider serves a more geographically diverse customer base and a wider variety of customers with different usage characteristics that enable the alternative supplier to provide service at a lower cost. There are other factors such as risk, the ability to have the customer reduce use during critical periods (e.g., Demand-Side Management), the relative contribution of each customer to peak periods, that also need to be considered.

(5) **Economies of Size May be Lost**. One of the traditional reasons for regulating LDCs was the belief that there are economies of scope (size) that permitted a large firm to procure gas at lower costs than several smaller firms. If there are economies of size, unbundling may result in inefficiencies unless the alternative suppliers are larger. Economists also recognize that there are diseconomies of size. There is a point beyond which larger companies become increasingly inefficient.

(6) **Normal Business Risk Increases.** It should be recognized that there is a high probability that some LDCs and alternative suppliers will not survive an intensely competitive gas market. Suppliers that are overpriced relative to their competitors will be the biggest losers. In extreme cases, there will be costs associated with bankruptcy or default.

B. Status of Small Customer Service Unbundling in the United States

The following table summarizes the state-by-state activity to unbundle rates and services for commercial and residential customers. While there are few pilot programs underway, it seems clear that there is a trend to more experiments to gauge the viability of competition in the core (residential and commercial) retail markets.

TABLE 14

State	Status of Small Customer Unbundling
California	Adoption of Permanent Core Aggregation Transportation (CAT program).
Connecticut	Requirement of firm transportation service to commercial customers (Docket No. 94-11-12). Connecticut Natural Gas filed an application to expand unbundling to residential sector (Docket 95-02-07).
Georgia	Notice of Inquiry investigation of pro-competitive activities including residential service unbundling. The Commission, however, voted to delay "Service Provider Selection Plan" for one year.
Illinois	CilCo plans to initiate "Power Quest", a pilot program to allow all customers an opportunity to purchase gas from other suppliers.
Indiana	Petition by Northern Indiana Public Service Company to allow gas-supplier choice (Cause No. 40342).
Iowa	Rock Valley Experiment.
Maryland	Pilot programs for residential customers starting in the fall of 1996. Small commercial customer unbundling began in 1995.
Michigan	Investigation of comprehensive service unbundling (Cause No. U-11017).
Minnesota	Proposed small-customer program (excludes residential customers)(Docket No. G-008/M-95-216) by Minnegasco.
New Jersey	Requirement of firm transportation service to commercial customers. Public Service Electric & Gas Company on August 23,1996 asked the New Jersey Commission for authority to implement a residential pilot program.
New York	Requirement to establish core (residential and commercial) aggregation programs.
Ohio	Proposed experimental transportation service (spring 1997) for residential customers (CINergy). Experimental transportation service for small customers (East Ohio Gas). LDCs encouraged by State Commission to conduct pilot programs for residential customers within 2 years.
Pennsylvania	Proposed (by Equitable Resources) pilot residential program and the formation of Global Issues Committee to study issues relating to small customer unbundling. Commission approved 2 year pilot residential program by Columbia gas.
Washington	Notice of Inquiry investigation of pro-competitive policies (Docket No. UG-940778).
Wisconsin	Public Service Commission authorized Wisconsin Gas' "Gas Advantage" pilot program.
Wyoming	White Paper recommended opportunities for load aggregation of all customers. PSC adopted KN Energy's experimental "Choice Gas Service" program.

Source: National Regulatory Research Institute

C. Retail Competition in the United States and Canada

The following discussion will briefly summarize the activities taking place in California and Canada. While New York has recently announced plans to initiate retail competition and there is a small-scale experiment in Iowa, California is the only state that has a "track record" of unbundling behind the citygate. Canada has considerable experience with retail competition and their experience is noteworthy. While the following discussion concentrates on

California and Canada, the reader is invited to review Appendix 1 for brief summaries of activities in other states.

1. California:

The Core Aggregation Transportation (CAT) Program began in February 1991. The CAT allowed core customers (consisting mostly of residential and small commercial customers with a few industrial customers) to combine their loads so they were sufficiently large to be attractive to different suppliers (referred to in California as "aggregators"). Initially, "core customer" was defined as any customer that did not have any alternative fuel options.

The experimental program placed limits on the number of customers that could participate (10% of total volume and 10 aggregators). During the experiment, customers could elect to purchase all or part of their requirements from an alternative supplier. The incumbent LDC would be responsible for the remaining supplies. Alternative suppliers were required to buy the LDCs proportional pipeline and storage facilities. While this provision limited the LDC's stranded costs, it also reduced any economic benefits that would be realized by the aggregators. Aggregators felt they could purchase a more efficient portfolio of transportation and storage services than the incumbent LDC.

> ***The California Public Utility Commission estimated that small customers were paying, on average, 70% more than large non-core customers for interstate pipeline capacity because of their inability to take advantage of competitive opportunities in interstate transportation markets.[26]***

Customer Participation:

In July 1995, the PUC announced significant modifications to and expansion of the CAT. The PUC concluded that recovery of stranded costs would be reduced and allow aggregators to construct their own supply portfolio. The Commission noted that any residential unbundling program should: 1) promote efficient use of the gas system, 2) provide core customers with service options, 3) assure that core customers continue to receive the level of service that they desire (high or low quality), and 4) assure a fair allocation of costs between customers and customer classes.

Prices:

Most core customers served by aggregators have saved some money compared to continued service from their incumbent LDC. The primary benefits, however, may be that the CAT provided a stimulus for LDCs to increase their operational efficiencies and the recognition that "unbundling" and innovative pricing benefits all customers.

Reliability:

The PUC placed the core customers above the non-core customers served by the LDC in the event that a curtailment was required. The LDCs were allowed to charge a $10/decatherm for "back-up service" but aggregators were allowed to trade positive and negative imbalances among themselves to limit the financial impact of these imbalance penalties.

Obligation to Serve:

The California PUC has taken the position that customers, not the LDC, should determine the quality and level of service that best meets their needs.

2. The Canadian Experience with Retail Competition

Prior to 1985, the Canadian regulatory environment was similar to the environment in the United States. There are important distinctions in the Canadian gas supply system that warrant comment. There are fewer pipelines in Canada so the viability of competition is more limited. TransCanada, for example, has a virtual monopoly in many regions. In this environment, Canada began its efforts to promote retail competition in 1985 with a series of intergovernmental accords such as *The Western Accord on Energy Pricing and Taxation* (March 28, 1985) and *The "Halloween Agreement"* also known as *The Agreement on Natural Gas Markets and Prices* (October 31, 1985). Among other things, these agreements allowed LDCs to reduce their wellhead contracts as their customers began to purchase gas directly from the wellhead.

> *The [Halloween] agreement among participating governments is intended to create the conditions for a new market responsive price system...it signals a return to market forces characterized by choices for buyers and sellers ...The new regime will provide a framework for negotiated prices between buyers and sellers. Prices will be affected by conditions in the marketplace; both supply and demand will influence price. Competition will be fostered which should increase the industry's ability to react quickly to changing conditions.*[27]

Manitoba became the first province to implement rules permitting residential customers an opportunity to purchase gas from other suppliers. The other provinces quickly followed.

Since the inception of the Ontario Energy Board's (OEB) program in 1987, approximately 250,000 residential customers now participate in the "buy/sell" alternative to traditional service from their LDC. In 1993, however, the spot price of gas exceeded the "Weighted Average Cost of Gas" (WACOG) and a few of the aggregators, brokers and marketers (ABMs) withdrew and customers were shifted back to their original LDCs. This resulted in hearings by the Ontario

Energy Board and the preparation of a "Code of Ethics" by the Direct Purchase Industry Committee (DPIC) even though only 2% of the customers were taking service from ABMs at this time. The Code of Ethics, among other things, specified the minimum notice period before a customer can switch suppliers, the minimum duration that a customer must stay with a supplier, ethical standards for marketing personnel and standardized disclosure statements. The OEB is currently considering a requirement to increase competition by forcing LDC's to separate their merchant and distribution functions.

British Columbia, on the other hand, initially promulgated tight regulatory rules over ABMs. ABMs had to use pipeline capacity from the LDC (this mitigated any stranded cost) and have long-term commodity contracts. It's also noteworthy that the British Columbia Commission's initial decisions (Inland Transportation in 1987 and Core Market Policy in 1988) approved unbundled access for only the largest industrial customers that were "knowledgeable." By 1992, the program was expanded to include commercial and residential customers and the requirements that ABMs have long-term commodity contracts were eliminated.

Residential Participation

At present, the participation levels for residential customers range from as low as 9% in areas traditionally served by Union Gas to as high as 34% in areas served by Consumers Gas. Participation levels have steadily increased notwithstanding the fact that the number of ABMs have declined.

Residential Prices

Initially the savings have been a result of lower spot gas at the wellhead compared to the mix of short and long-term prices that are in the LDC portfolios (the WACOG) and varied from Province to Province. For LDCs, the WACOG's often were disproportionately burdened by high-priced contracts so it was easy for an ABM to assure savings to the customer. Today, most of these high-priced contracts are no longer a problem for the LDC and the price advantage of the ABM over the LDC is less compelling. The provincial regulatory commissions that were more aggressive in requiring unbundling of services and related prices showed the most marked decrease in prices. Gas prices in Ontario, for example, declined from 19% above the national average in 1985 to 9% above the national average in 1994. Manitoba, on the other hand, did not require aggressive unbundling and had prices increase from 97% of the national average to 107% during the same period.

Reliability

The Ontario Energy Board did not exercise stringent oversight of the ABMs to ensure reliable service. The OEB took the position that this was an important aspect of the consumer's decision and the customers should accept the risks.

Unbundling of Services

"The Canadian experience demonstrates that providing unbundled residential access is not really that difficult".[28] Probably the most compelling argument in favor of unbundling is the emergence of innovative pricing that results in more accurate price signals. That is, the customer is more likely to be charged for the competitive market price of gas by assuming the risks for swings in the price and reliability of supply.

Consumer groups and ABMs have complained that the present structure favors the incumbent LDC and further unbundling is required. Consumer groups and ABMs note that the LDC is both a merchant and a gatekeeper to the distribution network. As evidence of improper conduct between the merchant and gatekeeper functions of the LDC, consumers and ABMs cite: 1) unclear or misleading information in customers' bills, 2) biased customer surveys, 3) the absence of customer education programs 4) continued use of buy/sell programs, and 4) control of gas purchase agreements that limit multi-year relations. There is also the contention that the utility's merchant service is being cross-subsidized by its distribution function. To the extent that cross-subsidization has occurred, the prices are distorted. To remedy these real or potential abuses, consumer groups and ABMs have urged the provincial regulatory commissions to adopt strict rules requiring a separation of the LDC's marketing and distribution functions and enforcement of rules governing affiliate transactions.

D. "Codes of Conduct" to Assure Fair Competition

As evidence of growing interest in competition at the distribution level, there is increased concern that the competition be "fair." One important concern for regulatory commissions and potential competitors of LDCs is the relationship between utilities and their marketing affiliates. To this end, FERC issued Order 497 that establishes "Codes of Conduct" for utilities in dealing with their affiliates. State regulatory commissions have also promulgated rules of the road for developing competition. The following summaries (see also Appendix 7) are intended to describe concerns that the FERC and state commissions have.

1. The Federal Energy Regulatory Commission

The FERC's "Standards of Conduct for Interstate Pipelines with Marketing Affiliates" were published in the Federal Register on Tuesday June 14, 1988 (beginning on page 22161). The specific standards of conduct are itemized in Appendix 7. Among other things, the FERC Standards only require "functional" separation of the marketing affiliate from the pipeline.

2. The Wisconsin Public Service Commission

The Wisconsin PSC in Docket 05-GI-108, relied heavily on the FERC Order 497 in formulating their "Standards of Conduct." Undoubtedly, the requirement for complete separation between the utility and its marketing affiliates is most significant. The PSC said that it was necessary to completely separate gas purchasing activities associated with providing regulated sales services from gas purchasing activities associated with providing unregulated services to foster competitive gas markets. This means that the marketing affiliate and the utility must be located in separate facilities (including its own phone system, support services, office supplies, furniture, computer system). The affiliate must also be self-supporting with its own personnel. This degree of separation would prevent the <u>perception</u> that preferential treatment would be accorded customer's of the utility's in-house sales structure compared to customers purchasing similar services from other market participants. This degree of separation will also prevent the utility and its affiliates from exercising undue market power. The PSC concluded that, absent complete separation, it would be impossible to assign upstream gas and capacity costs between regulated and unregulated markets. The PSC reasoned that since gas is purchased for regulated and unregulated markets, with different combinations of prices and firmness, that it would be impossible to ascertain which gas was purchased for the regulated markets and what was purchased for the regulated markets. Consequently, there is too much danger of cross-subsidization of the competitive market by the non-competitive market. Compared to the limited advantages of common capacity purchases and supply (e.g., economies of size and diversity of gas procurement), the risks of unfair market power are too great to allow the utility and its marketing affiliate to have any links.

> Markets will be deregulated when effective, sustainable competition exists...Accordingly, the central issue is the degree of financial and structural separation required to be maintained for gas purchasing activities associated with serving regulated markets...In addressing this issue and other issues associated with the restructuring of the gas industry, the Commission intends to be guided by the following principles...
>
> - Competitive markets are preferred to regulation.
> - On a long-term basis, consumers of all customer classes should benefit or at least be held harmless by any changes.

- Deregulation does not guarantee a competitive market. Deregulation of services should only take place where competitive markets exist, are effective, sustainable and in the public interest.
- Any PSC imposed strictures should protect new and unaffiliated market participants from the unfair exercise of market power.
- One of the benefits of competition should be increased customer choice.
- The marketplace should provide access to the maximum amount of information needed by customers to make informed decisions regarding gas service choices.
- Gas utilities should have an opportunity to recover prudently incurred, verifiable, material stranded costs.
- Safe and reliable service must be maintained.
- Regulatory, social, environmental and financial commitments have been made in the past and should not be ignored or discarded in the transition to a new structure.

3. The New York Public Service Commission

The New York PSC[29] approved an LDC restructuring plan that is intended to open up the markets for commercial and residential customers sometime in 1996 (Restructuring of the Emerging Competitive Natural Gas Market Opinion No. 94-26 issued 12/20/1994 and Order on Reconsideration issued 8/11/1995 and Docket 96023-G-0932). The plan was an attempt to develop a policy framework to: 1) Assure fair competition by marketers and the LDCs and 2) provide access to supply options for as many customers as possible. 3) ensure quality of service at affordable rates for core customers who cannot access new sources and 4) continue existing customer protections.

4. The New Jersey Board of Public Utilities

The New Jersey Board of Public Utilities adopted standards of conduct to govern transactions between local distribution companies and their marketing affiliates. The FERC standards, initially adopted in Order 497, served as the basis for the New Jersey rules.

> The Standards are intended to promote fair competition among all participants in the natural gas marketplace, and to create barriers to prevent self-dealing. (See Appendix 7 for the actual Codes of Conduct)

5. The Maryland Public Service Commission

The Maryland PSC's Standards of Conduct were in response to a Petition by Baltimore Gas & Electric to create an unregulated marketing affiliate -Baltimore Natural Gas - that would provide brokerage services. The Commission held that the relationship between BG&E and its affiliate should be financially separated. Accordingly, to prevent cross-subsidizes flowing from BG&E's captive customers to the un-regulated affiliate, all costs and revenues for BNG shall be considered as "below the line" and thus have no impact on BG&E's rates to its captive customers. BG&E's shareholders would realize all of the benefits and bear most of the risk.

a) Allocations should be made on the basis of fully-distributed cost allocation methodology;

b) For transactions in which BG&E provides benefits to the subsidiary, the cost of any of these services should be based upon the full cost of such service, including both direct and indirect costs that can be clearly ascertained.

c) For services which could reasonably be marketed by BG&E to the public and which have clear value to the subsidiary, fair market value of such services must be allocated as the imputed cost; and

d) For transfers of assets, symmetric pricing principles will be adopted as necessary for the protection of the regulated utility operations, so that transfers of assets between the parent to the affiliate should be recorded at the greater of book cost or market value, whereas transfers from the non-regulated operations to the utility operations should be the lesser of book cost or market value.

Essentially, BNG would be treated as any other marketer. As a result, the Commission did not find it necessary to regulate BNG since sufficient competition was emerging in the gas market. To provide adequate assurance that BNG and BG&E can not exercise undue market power, the Commission adopted specific codes of conduct.

6. The Massachusetts Department of Public Utilities

On August 16, 1996, the Department of Public Utilities issued a Notice of Proposed Rulemaking to establish codes of conduct for LDCs and their marketing affiliates. As with the Wisconsin Standards of Conduct, the Massachusetts Commission believes that functional unbundling may not be sufficient to prevent abuses.

> The Department of Public Utilities is proposing to adopt a regulation to govern the relationship between natural gas local distribution companies, regulated by the Department, and their unregulated marketing affiliates. The proposed rule would establish standards of conduct to ensure that all as suppliers and transportation customers are subject to the same rules, have access to the same information, and are treated equally by the LDC and its employees responsible for the transportation of gas.

As a predicate for the rulemaking, the DPU noted that the gas industry has become increasingly competitive as a result of the deregulation of wellhead gas prices and the unbundling of pipeline transportation of natural gas. The DPU further noted that competition can provide benefits that a regulated system can not. The Commission cautioned, however, that deregulation without competition would be a disaster for consumers. To ensure competition, the Commission said that there should be:

(a) many buyers and sellers with effective access to each other,
(b) arms length transactions between buyers and sellers,
(c) broad and equal access to timely information,

(d) low thresholds for entry into the retail gas markets, and most importantly.
(e) no market participant, or group of participants, is in a position to exert unfair or abusive market power in an competitive industry structure.

7. The Ohio Public Utilities Commission

Under the Agreement with Ohio Gas Company, the LDC will purchase and redeliver gas to "agency" transportation customers (end-users). The rate will consist of a fixed customer charge per month, a fixed transportation charge, a volumetric record keeping charge, a fee for nominations (forecasting) an allowance for unaccounted for gas, and balancing services. The Commission is considering codes of conduct to apply to the LDC and its affiliates. The Commission noted:

> *Our approval of these contracts does not constitute state action for the purposes of the antitrust laws. It is not our intention to insulate the applicant or any party...from the provisions of any state or federal law which prohibit the restraint of trade.*[30]

8. The Missouri Public Service Commission

A stipulation ended the practice, by an LDC, of selling transportation service to a marketing affiliate that, in turn, would sell bundled service to various large commercial customers on the LDC's system.[31]

9. The Rhode Island Public Utilities Commission

Issued Notice of Proposed Rulemaking to establish rules regarding the regulation of marketers and LDC/Affiliate standards of conduct.

E. Stranded Costs

For pipelines, the process of "de-contracting" for bundled pipeline services (e.g., transportation, storage, balancing) was responsible for the stranded cost issue in the pipeline sector of the natural gas industry. Given the interstate nature of pipelines, the stranded cost issue was handled by the FERC.

> *More than four years after the issuance of the restructuring rule, interstate pipelines have nearly completed the arduous process of establishing the magnitude of Order 636 transition costs across the industry. And, while pipelines have paid most of those costs and started the ball rolling to recoup an estimated $4 billion from customers, the recovery process is far from complete. According to figures compiled by the Commission (FERC), interstate pipelines to date have filed to recover a total of $3.3 billion in eligible transition costs, with gas supply realignment responsible for just over half of that at $1.88 billion. Taking into account a few unresolved GSR cases that are likely to add large chunks of money to the pile and push the total tab over $4 billion, it appears that pipelines did a fair job of forecasting potential liability in the immediate wake of Order 636. Estimates requested by the*

FERC and reported by the General Accounting Office in 1993 totaled $4.8 billion, with $3.3 billion of that pegged to the GSR process.

For instance, ANR Pipeline Co., has made 14 filings, mostly for GSR costs totaling $115.9 million, while Columbia has made 20 filings covering non-GSR costs and Northern Natural Gas Company has come in 25 times to commence recovery of various costs, including packages totaling $195 million in GSR costs...As pipelines phase out their Order 636 surcharges, residential customers on average will see their bills reduced by $1 per month. The Commission's compilation of filed costs charts the four basic transition- cost categories. GSR, Account 191, Stranded costs and new facilities. The GSR total currently stands at $1.88 billion, followed by stranded costs at $825.3 million, Account 191 at $604.7 million and new facilities at $12 million. [32]

It should be noted that the FERC found the stranded cost problem to be one of the most contentious issues they faced in their efforts to stimulate competition in the wholesale gas markets.

In a future of retail unbundling and competition, LDCs may be faced with stranded costs associated with their distribution pipelines, storage facilities, gas supply contracts and other aspects of their systems. In some cases, lower utilization of facilities (e.g., local storage and supplemental peaking) may be a significant problem for some gas LDCs.

Unlike the electric utility industry, where several observers have offered their views on the potential extent of stranded costs, there have been not been similar studies to estimate the magnitude of stranded costs for gas LDCs. The magnitude of stranded costs may, however, be decreasing for LDCs as more LDCs have replaced many of their long-term contracts with one to three-year contracts for pipeline and storage capacity. The development of a robust market for reselling excess capacity will also help LDCs mitigate stranded costs. In some instances, LDCs have included "force majeure" clauses in their contracts that enable them to reduce their purchases in event that customers switch to alternative suppliers. These trends suggest that stranded costs will be small.[33]

1. Definitions of Stranded Costs

There is no universally accepted definition. As a result, there is no agreement on how to calculate stranded costs. Professor William Hogan of Harvard University offered this simple definition of stranded costs.

The difference between the competitive market value and the regulated book value is the value of the potential stranded asset.

The National Regulatory Research Institute provided the following more detailed definition of stranded costs:

Where a customer has a legal obligation to bear certain costs, and finds a way to avoid that obligation, the costs are truly 'stranded.' 'Stranded' costs, therefore, result not merely from costs exceeding market, but from customers leaving without paying costs incurred on their behalf. Put another way, the term 'stranded' should apply only where there is a violation of the quid pro quo. There is a violation of the quid pro quo where (a) the utility was compelled (by contract or franchise) to make an investment and (b) a customer for whom the investment was intended avoids its cost responsibility for that investment.

2. Dealing with Stranded Costs

To the extent, if any, that the IURC has to address the issue of stranded costs for gas LDCs, the Commission will be asked to referee competing claims among the LDCs, competitors of the LDCs, and consumers. Using the experience of pipeline unbundling, LDCs may advance the position that they should be allowed to recover prudently incurred costs that were required to meet their obligation to provide reliable service at the lowest possible cost. On the other hand, if the debate in the electric utility industry serves as a guide, opponents of stranded cost recovery may argue that it is inappropriate to insulate a firm in a competitive industry from the normal risks of doing business. After all, firms in a competitive industry can not set prices for their goods and services that exceed the market price. To allow an LDC to recover those costs would delay competition and deny benefits of a competitive market to customers of the LDC.

Parties may also claim that allowing an LDC to recover all stranded costs would not provide incentives for the LDC to mitigate those costs. Proponents of this "middle ground" suggest that the LDC should absorb some of the costs to induce efficiency and to mitigate concerns that the LDC would try to inflate the stranded costs.

F. Performance-Based Regulation (PBRs) or Incentive Regulation

1. PBRs vs. Traditional Cost-of-Service

Historically, LDCs have been subject to "Cost-of-Service" (COS) and "Rate-of-Return" (ROR) regulation. Other forms of regulation may be appropriate as a result of increased competition between incumbent LDCs and other suppliers of natural gas. Performance-based (incentive) rates have touted, primarily, as a transition tool to emulate a competitive market and enable smaller customers some of the benefits of a competitive gas market. As a transitional mechanism, PBRs would be applied to "captive customers" while the "market" would determine the prices for various services for customers with competitive options. PBRs are intended to give the LDC an incentive to reduce costs by allowing the LDC to retain some portion (or all) of the savings. In the event that an LDC's cost exceed the cost level prescribed by the PBR, the LDC and its investors pay some portion of the difference to customers. To better understand PBRs, it is necessary to briefly discuss traditional cost-of-service methods.

Cost-of-service defines costs that a utility needs recover and allocates these costs to the various types customers. With regard to determining costs, a utility is allowed to recover operating costs such as taxes and depreciation, costs associated with investment in their infrastructure, and a return on their investments that is intended to compensate investors for putting their capital at risk and attract new capital. These are typically "historical" costs with "proforma adjustments" for "known and measurable" changes in the future. Regarding the allocation of costs, C-O-S is intended to assign costs to customers based on the costs that they impose on the LDC (e.g., The extent to which various classes of customers contribute to the peak demand of the LDC.) Since traditional cost-of-service is predicated on historical (sometimes referred to as accounting, embedded or average costs), they are relatively easy to determine and audit.

The Indiana Electric Association, in a memo announcing their support for S.B.637, succinctly summarized the virtues and concerns for traditional cost-of-service ratemaking:

> *Under current practice, a utility's rates and earnings are often tied to its accounting costs. The intent is to ensure that utilities' rates reflect the legitimate costs of doing business, plus a fair return. The unintended effect, however, can be a 'cost-plus' mentality that does not encourage efficiency. Utilities can actually be rewarded more for justifying costs than for controlling them.*

The General Assembly adopted IC 8-1-2.5 that, among other things, explicitly allows the Commission to consider performance-based rates and other alternative regulatory options.

> Section 1: The Indiana general assembly hereby declares the following:
>
> (1) That the provision of safe, adequate, efficient, and economical retail energy services is a continuing goal of the commission in the exercise of its jurisdiction.
> (2) That competition is increasing in the provision of energy services in Indiana and the United States.
> (3) That traditional commission regulatory polices and practices, and certain existing statutes are not adequately designed to deal with an increasingly competitive environment for energy services and that alternatives to traditional regulatory policies and practices may be less costly.
> (4) That an environment in which Indiana consumers will have available state-of-the-art energy services at economical and reasonable costs will be furthered by flexibility in the regulation of energy services.

(5) That flexibility in the regulation of energy services providers is essential to the well-being of the state, its economy and its citizens.
(6) That the public interest requires the commission to be authorized to issue orders and to formulate and adopt rules and policies that will permit the commission in the exercise of its expertise to flexibly regulate and control the provision of energy services to the public in an increasingly competitive environment, giving due regard to the interests of consumers and the public and to the continued availability of safe, adequate, efficient, and economical energy service.

Specifically, the new law provides that the Commission may:

(1) Adopt alternative regulatory practices, procedures, and mechanisms, and establish rates and charges that:
- (A) are in the public interest...; and
- (B) enhance or maintain the value of the energy utility's retail energy services or property...

(2) Establish rates and charges based on market or average prices, price caps, index based prices, and prices that:
- (A) use performance based rewards or penalties, either related to or unrelated to the energy utility's return or property; and
- (B) are designed to promote efficiency in the rendering of retail energy services....

The law also states that the "Commission may approve, reject, or modify the energy utility's proposed plan if the commission finds that such action is consistent with the public interest. However the commission may not order that material modifications changing the nature, scope, or duration of the plan take effect without the agreement of the energy utility ... An energy utility may withdraw a plan proposed under this section without prejudice before the commission's approval of the plan, or the energy utility may timely reject a commission order modifying its proposed plan under this section without prejudice. However, the energy utility may not file a petition for comparable relief under this section for a period of twelve (12) months after the date of the energy utility's withdrawal of its proposed plan or the date of the energy utility's rejection of the commission's order, whichever is applicable."

Performance-Based Rates are intended to break the utilities' "cost plus mentality" by divorcing costs from rates. There are numerous methods for calculating PBRs. A PBR could entail "targeted" incentives aimed at particular costs, such as gas procurement. A PBR could also be broader to encompass the LDC's total cost of doing business (typically only those costs that the utility has some degree of control).

PBRs are not without some degree of controversy. Two of the most common forms of incentive ratemaking are "Price Caps" and "Yardstick Regulation". Since the purpose of this paper is to merely give a flavor for PBRs, other forms of incentive regulation, such as "Revenue Caps" will not be discussed.

Price caps are, perhaps, the most prominent recent regulatory innovation. Simply stated, a price cap sets a fixed ceiling for prices that the firm can charge. In practice, price caps permit a utility to increase its prices up to a certain maximum (e.g., up to the Consumer Price Index or CPI) without regulatory review. Recognizing that the bundle of goods and services that comprise the CPI may have little to do with the costs that a specific utility faces (e.g., the telephone industry is characterized as a "declining cost" industry), some price caps include a "productivity offset". As with the initial index, finding a productivity offset that is above controversy has not been possible. Concern has also been voiced that price caps, by encouraging cost reductions, may cause a utility to reduce its routine maintenance and its customer service (see for example the Oregon Public Service Commission's termination of an Alternative Regulation Plan for U.S. West Communications. In this case, the PUC Staff noted:

> *a severe increase of service quality problems over the past 4 years including an excessive number of customer complaints.*[34]

To develop a meaningful price cap, the indices would have to reflect the expected cost trends and provide incentives for improved performance. It's difficult for a regulatory commission to have the quantity and quality of information necessary to develop price caps that are uniquely tailored to a particular company. That is, allocative efficiency suffers when the prices do not reflect costs and may have to be recelebrated from time to time. For these reasons, some have suggested "yardstick" regulation.

Yardstick regulation allows utilities to adjust their rates so that they are comparable to a group of other utilities. Intuitively, this has some appeal since a competitive market would make comparisons to competing firms. In an intensely competitive market, the prices and quality of service should gravitate to the standards set by the very "best" firms. Utilities that exceed the performance of the best utilities would be rewarded while utilities that fell short of exemplary performance would not realize any benefits and may be required to compensate their customers for sub-standard performance.

In some instances, price-caps and yardstick regulation have been designed to share the benefits and costs between shareholders and customers. This is sometimes referred to as "sliding scale" regulation. For illustrative purposes, if a company exceeded its performance standard, the company might allocate 50% of the benefits to shareholders and 50% of the benefits to customers. Of course, there are any number of sharing approaches that may pass muster for equity and efficiency.

Because broad use of PBRs is a relatively recent development, there is not a great deal of evidence to either support or reject the general notion of incentive ratemaking or specific forms of PBRs. For this reason, many states have authorized limited pilot (experiments) programs to determine the efficacy of various forms of PBRs.

The Indiana General Assembly, with the passage of S.B. 637 (IC 8-1-2.5) in 1995, enables the IURC to consider PBRs that are advanced by the LDC. Northern Indiana Public Service Company (NIPSCo) has been negotiating a PBR with a variety of interested parties [On the electric side, the Rural Electric Cooperatives have proposed an Alternative Regulatory Program]. To date, the Commission is still in the process of considering these proposals.

2. The Experience of Other States

California:

The California PUC has adopted PBRs, on an experimental basis, for its major combination utilities Pacific Gas & Electric Company and San Diego Gas & Electric Company. In 1996, the Commission rejected arguments that the PBRs for San Diego Gas & Electric caused "perverse results." The experimental plan allows the utility to earn 300 basis points above its authorized return without triggering an adjustment. *San Diego Gas & Electric* Application 92-10-017 Decision 96-04-057, April 10, 1996. Pacific G&E has an experimental program that would give them incentives to procure cheaper gas supplies for core customers (Docket A94-12-039). Southern California Gas requested authority to implement an incentive plan that would allow customers and shareholders to share revenues associated with releasing some of their firm pipeline capacity.

Colorado:

The PUC has a rulemaking in progress that could eliminate the automatic Gas Cost Adjustment Clause or merely streamlining the clause to permit incentive's for the LDC to beat market prices.

Connecticut:

The Connecticut Department of Public Utility Control (*re:* Connecticut Natural Gas Corporation *Docket 95--02-07* October 13, 1995) The Commission required the Company to share net profit margins, in excess of the target margin, between ratepayers and shareholders. The Commission also encouraged the LDC to aggressively market its unneeded pipeline capacity and gas. The LDC was authorized to share profits between shareholders and ratepayers associated with "capacity release" and "off-system" sales. The Commission did, however, deny the

Company's request to recover lost profits that resulted from large industrial customers switching from firm to interruptible service.

Minnesota:

The Minnesota PUC approved a "symmetric" performance-based gas purchasing plan for Minnegasco, a natural gas LDC. The Company and its customers would share any benefits if the LDC beats two benchmarks: 1) A market-based benchmark with demand and commodity components. 2) A comparison of volume-weighted, average, total annual gas cost per million Btus.[35]

New York:

Brooklyn Union became the first LDC to receive permission to institute a "price-cap." The plan would establish price caps for the non-price component in customer bills through the year 2002.

For a more complete listing, please see the following table.

TABLE 15
SUMMARY OF STATE ACTIVITIES REGARDING FLEXIBLE PRICING PRACTICES

	Load Retention Rates		*Economic Development Rates*				Performance
	Rates Offered	Do Rates Exceed MC	Rates Offered	Do Rates Exceed MC	Applic-able Load	Flex. Rates	Based Rates (PBRs)
Alabama	Yes	Yes	Yes	No	A,C		
Alaska	No	n/a	No	n/a	n/a		
Arizona	Yes	Yes	Yes	Yes	A,C		
Arkansas	Yes	Yes	Yes	Yes	A,C		
California	Yes	Yes	Yes	Yes	A,C		Yes
Colorado	Yes	Yes	No	n/a	n/a		
Connecticut	Yes	n/a	Yes	n/a	A,C		
Delaware	No	n/a	No	n/a	n/a		
D.C.	Yes	Yes	Yes	n/a	n/a		
Florida	Yes	Yes	n/a	n/a	n/a		
Georgia	Yes	Yes	Yes	Yes	A,C		
Hawaii	n/a	n/a	n/a	n/a	n/a		
Idaho	No	n/a	n/a	No	n/a		
Illinois	Yes	Yes	Yes	Yes	A,C		
Indiana	Yes	Yes	Yes	Yes	A,C		
Iowa	Yes	Yes	Yes	Yes	B,C	Yes	
Kansas	Yes	Yes	Yes	Yes	A,C		
Kentucky	Yes	Yes	Yes	Yes	A,C		
Louisiana	Yes	n/a	Yes	n/a	A,C	Yes	
Maine	Yes	Yes	Yes	Yes	B,C		Yes
Maryland	No	n/a	Yes	Yes	B,C		
Massachusetts	Yes	Yes	Yes	Yes	B,C		
Michigan	Yes	Yes	Yes	Yes	A,C		
Minnesota	Yes	Yes	Yes	Yes	A,C		
Mississippi	No	n/a	No	n/a	n/a		
Missouri	Yes	Yes	Yes	No	A,C		
Montana	Yes	Yes	n/a	n/a	n/a		
Nebraska	n/a	n/a	n/a	n/a	n/a		
Nevada	Yes	Yes	No	n/a	n/a		
New Hampshire	Yes	Yes	Yes	Yes	A,C		
New Jersey	Yes	n/a	Yes	n/a	n/a	Yes	
New Mexico	Yes	n/a	Yes	n/a	A,C		
New York	Yes	Yes	Yes	Yes	B,C	Yes	Yes
N. Carolina	Yes	Yes	Yes	Yes	B,C		
North Dakota	Yes	Yes	Yes	Yes	A,C		
Ohio	Yes	Yes	Yes	Yes	A,C		
Oklahoma	No	n/a	Yes	No	A,C		
Oregon	Yes	Yes	Yes	Yes	A,C		
Pennsylvania	Yes	No	Yes	No	A,C		
Rhode Island	No	Yes	Yes	No	A,C		
S. Carolina	Yes	No	Yes	No	A,C		
Tennessee	Yes	Yes	Yes	No	A,C		
Texas	Yes	Yes	Yes	Yes	A,C		Yes
Utah	Yes	Yes	No	n/a	n/a		
Vermont	No	n/a	Yes	Yes	A,C		
Virginia	Yes	Yes	Yes	Yes	A,C		
Washingtion	Yes	n/a	Yes	n/a	B,C		Yes
West Virginia	Yes	Yes	Yes	Yes	A,C		
Wisconsin	Yes	Yes	No	n/a	n/a		
Wyoming	Yes	Yes	Yes	Yes	B,C		
TOTAL % YES:	80%	67%	76%	53%		8%	10%

Source: "Public Utilities Fortnightly", derived from National Association of Regulatory Utility Commissioners, Utility Regulatory Policy in the United States and Canada 1994-1995 1) MC = Marginal Cost, 2) Given the extent of activity, this table may not be current. 3) A = Existing Business -Only Incremental Load, B = Existing Business -Any Load, C = New Business -Entire Load,

G. Reliability Transmission and Storage Under-Subscription?

Historically, twenty-year contracts were commonplace for bundled pipeline services. The FERC often required this level of security before granting "Certificates of Public Convenience and Necessity" for construction of interstate pipelines. FERC's Order 636 changed this dynamic by:

1 Requiring the unbundling of gas sales from transportation services
2) Establishing capacity release and the secondary (gray) market
3) Changes to the pipelines "obligation to serve"
4) Adopting "Straight-Fixed Variable" (SFV) rate design

Following implementation of Order 636 in 1993, that relieved pipelines of their historical obligation to serve, all but a few pipeline sales contracts were terminated and the transmission capacity was released. As a consequence, LDCs have relied on "educated guesses" to balance reliability and costs since they could no longer count on pipelines to provide bundled service. LDCs and other customers had to re-subscribe to pipeline services (i.e., no-notice, firm transportation, interruptible transportation, storage services as well as the newly "released" capacity that opened the market for short-term firm contracts). In this process of terminating long-term contracts, some of the pipelines became "under-subscribed". This is one of the "stranded cost" issues faced by the gas industry. The under-subscription of transportation capacity, in turn, resulted in financial concerns for the pipelines.

According to the INTERSTATE NATURAL GAS ASSOCIATION OF AMERICAN (INGAA) in a report entitled: *"The Effect of Restructuring on Long-Term Contracts for Interstate Pipeline Capacity"* - September 1995.

> [Prior to Order 636] *96% of pipeline capacity was under firm contracts...which included 4% under short-term firm contracts [In this region the amount was 7%]. Contracts for nearly half of pipeline capacity will expire between 1995 and 2002...Between 1994 and 2002, the amount of contracted firm capacity is expected to decline from 96% to 87% of total capacity. Long term contracts will be of shorter duration. Over half of the resubscribed capacity will be for contract terms of 4 years of less.*

The LDC CAUCUS in their December 1995 Report *"Future Unsubscribed Pipeline Capacity"* noted on page A-6 and A-7 that Indiana and the North Central-East region generally have 42% excess capacity (30.2 Bcf/day demand and 42.8 Bcf/day capacity) only East South Central (e.g., Louisville) and California have greater excess capacity (49% and 51% respectively). Moreover, on a Average Day the excess pipeline capacity balloons to 68%.

The El Paso's pipeline (*El Paso Natural Gas Co. 72 FERC ¶ 61,083 at page 61,441 - 1995)*, proposed: 1) an "exit fee" for customers that did not renew their capacity and 2) requiring the remaining customers to pay the balance of any stranded costs. The FERC recognized that having captive customers pay for the capacity turn-backs would result in substantial harm. The FERC noted that for pipelines to unilaterally impose exit fees would violate the intent of Orders 636 and 636-A. Further, the FERC was persuaded that the shareholders and customers should jointly bear the financial risks to ensure that El Paso would be under pressure to mitigate its stranded costs. As a result, the FERC rejected El Paso's proposal to enact an exit provision and to shift costs to the remaining customers.

> *The Commission recognizes that some cost sharing may be appropriate when a large, historic customer leaves a system that was originally designed to meet its needs. When historic customers terminate service at the end of their contracts it is not appropriate to expect the remaining customers, specifically [East of California] customers in this case, to pay all the remaining costs of the pipeline. The pipeline has some obligation to attempt to develop new business opportunities to make use of its unused capacity. Therefore, a cost sharing mechanism should not diminish the pipeline's incentive to market its unused capacity.* -72 FERC at 61,441.

With regard to the LDCs' perspective, compensating pipelines for under-subscribed capacity imposes additional costs that they have to pass-on to their customers or shareholders. To mitigate the costs, according to the INGAA, most LDCs will reduce their contract horizons from the 10-20 years that was commonplace prior to Order 636 to 1-12 years. It is also likely that some LDCs may decide to reduce reliability, by placing greater reliance on interruptible transportation, as a means of mitigating the increased cost. Given the relatively low load factors and the FERC approved SFV rate design that makes it costly to reserve capacity, LDCs are likely to experience the largest cost increases associated with unsubscribed pipeline capacity. The American Public Gas Association said:

> *The growing problem of unsubscribed pipeline capacity is a cancer on the natural gas industry. It threatens to erode the long-standing relationships between buyers and sellers that produce economic and reliable gas service...*

The problems attendant to unsubscribed capacity are likely to be more acute for smaller LDCs. According to the American Public Gas Association there were 950 municipal, county or public utility district gas systems in the United States in 1995. **95% of these were served by only one pipeline.** By way of example, customers of El Paso and Natural Gas Pipeline filed petitions with the FERC that would spread the costs of unsubscribed capacity that would increase rates to municipal customers by 50%. A survey conducted by APGA showed:

> A dramatic difference between the way smaller LDCs (less than 50,000 Mcf/day usage) and the largest LDCs (more than 300,000 Mcf/day usage) approach capacity needs. Only 15% of the smaller LDCs indicated that they expected to reduce their interstate pipeline capacity rights, while nearly

65% of large LDCs indicated that they would trim contracts. Only 15% of the small LDCs preferred contracts of 1-3 years with pipelines, while 35% of large LDCs preferred a shorter contract term.[36]

If LDCs unbundle their services to allow for competition, and if LDCs are relieved of their "obligation to serve", the trend to de-contracting may accelerate and increase the amount of unsubscribed transmission capacity. As LDCs face increasing competition for customers, there will be a corresponding temptation to tilt the balance in favor of reduced costs, and at the expense of reliability (e.g., increased reliance on interruptible capacity as a substitute for firm capacity since there is a low probability that the use would be interrupted as a result of the surplus capacity).

H. Gas Planning and Demand-Side Management

Gas Planning

In an intensely competitive energy market, the uncertainty that any particular customer will remain with an LDC may increase the importance of forecasting and planning. In addition to competition from other suppliers of natural gas, LDCs will be increasingly concerned with competition from providers of electric power services competing to serve specific end-uses. The ability of a utility to prosper in a competitive environment will largely hinge on its ability to accurately forecast its needs and develop appropriate supply portfolios. Even in the absence of retail competition, LDCs have begun to alter their supply portfolios to reduce their risks by concentrating on short-term contracts. Now it is rare for LDCs to include a substantial amount of long-term contracts in their gas supply portfolios. While its true that competition entails additional risks, it may be that a competitive market will improve efficiencies. Fitch Investment Services made the following observation concerning the need for planning by gas utilities.[37]

> *Changes in the natural gas industry and increasing competition have greatly amplified planning uncertainties and risks for local distribution companies. As a result, LDCs likely will exhibit more diverse credit profiles. Moreover, an LDC's credit quality will increasingly depend on innovative and aggressive management initiatives to provide reliable, low-cost, efficient service. Integrated Resource Planning gives LDCs a framework for developing resource plans with enough flexibility to respond to a diversity of industry risks. A well designed IRP is a planning and operating tool that management can use to shape the load curve, use existing assets more efficiently, avoid some capital expenditures...and acquire more diverse supplies less expensively.*

Prior to FERC's Order 636 that required pipelines to unbundle their services and distance themselves from the merchant function, pipelines had the primary responsibility for gas supply planning. LDCs, against a back-drop of volatile gas prices during the 1970s and 1980s, emphasized long-term transportation and gas supply contracts to minimize price and reliability risks. The comments by Mr. Richard Green CEO of UtiliCorp, seemed to reflect the sentiment of LDCs:

> UtiliCorp believes that an LDC cannot focus on the short-term to the neglect of the long-term. For example, the relatively low-priced gas available today under short-term supply contracts will inevitably disappear during periods of supply shortages. LDC's who are today locking in long-term supply contracts are acting prudently, even though prices under short-term contracts may be somewhat lower.[38]

Increased competition at the wellhead following FERC's Order 436, an increased interest in gas planning as evidenced by the passage of the National Energy Policy Act of 1992 (EPAct), Order 636 and the potential for retail competition have combined to cause many LDCs to re-think their planning processes. Section 115 of the required state commissions to consider whether it is appropriate to require gas utilities to undertake Integrated Resource Planning (IRP) and adopt Demand-Side Management (DSM).

> *Each gas utility shall employ integrated resource planning in order to provide adequate and reliable service to is gas customers at the lowest system cost. All plans...shall (A) be updated on a regular basis, (B) provide the opportunity for public participation and comment, (C) provide methods of validating predicted performance, and (D) contain a statement that the plan can be implemented after approval of the State regulatory authority...* [As defined by EPAct, IRP is] *planning by the use of any standard, regulation, practice, or policy to undertake a systematic comparison between demand side management measures and the supply of gas by a gas utility to minimize life-cycle costs of adequate and reliable utility services to gas customers. Integrated resource planning shall take into account necessary features for system operation such as diversity, reliability, dispatchability, and other factors of risk and shall treat demand and supply to gas customers on a consistent and integrated basis.* §115(b)(3)

According to the Gas Research Institute,[39] About 16 states adopted IRP standards in response to the federal mandates or already required comprehensive planning by gas utilities. The following is a partial list of states that adopted gas IRP:

- California adopted IRP Rules for gas utilities in D-92-12-058
- Connecticut's 10 year planning requirement adopted in *Docket 93-03-17* based on the Connecticut Legislature's Act 89-50,
- Delaware's five year planning standard required by *Order 3731*,
- Idaho Order 25342
- Michigan's biennial filing requirements were adopted in *Case U-10589*,
- Minnesota's annual gas procurement and conservation were filings adopted in *Docket G999/CI-93-895*
- North Carolina recently revised its gas IRP requirements *Docket L-00920066* January 11, 1996
- Wisconsin's IRP Rules were adopted in *Docket 05-GI-107*

The California Public Utility Commission stated that objective of Integrated Resource Plans were to meet customer needs at the lowest total cost:

> *Resource planning defines and justifies the facilities that a utility will build to meet customer service requirements. Transmission and storage are the focus of the planning process because they are 'big ticket item' investments requiring a long planning horizon...As a result, a utility will be able to design its facilities to be large enough to meet peak demand...The other part of the planning process is determining the level of reliability that each utility's system should provide.* (47 CPUC 2d at 449)

Many states, such as Illinois and Arizona, either have declined or not acted on the federal standards. In Arkansas, the Commission is reviewing the planning practices of its gas utilities and notes that these utilities have some gas Demand-Side Management in place. The Arkansas Public Service Commission declined to require IRP provided the gas companies reform their pricing policies. Indiana has not formally acted on the federal standards. Despite the lack of state imposed standards, Southern Indiana Gas & Electric Company's, does have an integrated planning process for their system that considers gas and electric planning, supply options and DSM.[40]

While not explicitly approving the EPAct's IRP requirements for gas utilities, the IURC has been concerned with gas utility forecasting, supply-side planning and use of cost-effective Demand-Side Management. The following case citation illustrates the Commission's concern following FERC's Order 636.

> *We are mindful that Petitioner's [Ohio Valley Gas] supply portfolio should remain resilient in the aftermath of the FERC's issuance of Orders 636 (April 8, 1992); 636-A (August 3, 1992); and 636-B (November 27, 1992) ...Yet gas storage is only a component of the supply portfolio and cannot be analyzed independent of other supply-side and demand-side alternatives. These alternatives should be responsive to the customer's need for reliable gas supply at the lowest reasonable cost. Before addressing any array of alternatives this utility might consider, we should mention the need to identify appropriate sources of information for improved load forecasting and planning...What Petitioner and other gas utilities are less familiar with is the need for reliability analysis in developing a resilient supply portfolio. The electric utilities have undertaken reliability analysis for some time but gas utilities have only recently been faced with this after FERC's Order 636...Such reliability analysis might answer the following questions facing each gas utility;*
>
> > *Will brokerage programs and market hubs improve reliability and economics?*
> >
> > *Will the widespread use of gas storage, combined with increased reliance on natural gas by electric utilities for summer peaking needs, reduce the historic summer and winter price differentials sufficiently to alter the present economics of storage?*
>
> *The Commission expects that Petitioner's next request for approval of gas storage or supply arrangements should set out its analysis of other alternatives which may include: brokerage arrangements for a richer portfolio; demand-side management, including various interruptible*

contracts with a variety of customers; and a diversity of producer and pipeline contracts. Finally, the Commission is concerned that future approval of storage and supply contracts, that are not subjected to the rigors of competition among alternatives, may also reduce the avoidable cost. As a result, other alternatives may not prove to be desirable because their avoided costs have been minimized by prior actions.

- Ohio Valley Gas Corporation, Cause No. 39770, December 22, 1993.

Demand-Side Management (DSM)

Demand-Side Management is generally regarded as including: conservation (reducing the amount of gas used), direct control (usually aimed at reducing the peak demand), and rate design (e.g., interruptible rates, real-time pricing). In response to federally mandated end-use efficiency programs and reduced usage by customers (e.g., price elasticity that might manifest itself in added insulation), the average household has reduced its gas usage by 33% over the last 15 years (PUF February 1, 1995 page 32). Commercial and Industrial customers have also experienced increases in end-use efficiencies. The EPAct required states to consider adopting DSM standards (Section 115(a) 9 & 10).

The rates charged by any State regulated gas utility shall be such that the utility's prudent investment in, and expenditures for, energy conservation and load shifting programs and other demand-side management measures which are consistent with the findings and purposes of the Energy Policy Act of 1992 are at least as profitable (taking into account the income lost due to reduced sales resulting from such programs) as prudent investments in, and expenditures for, the acquisition or construction of supplies and facilities. The objective requires (A) regulators link the utility's net revenues, at least in part, to the utility's performance in implementing cost-effective programs promoted by this section; and (B) regulators ensure that, for purposes of recovering fixed costs, including its authorized return, the utility's performance is not affected by reductions in its retail sales volumes.

Since gas utilities are not nearly as capital intensive as electric utilities, the "avoidable" costs are much less for gas utilities. As a result, DSM is viewed as being more applicable to electric utilities. Many state commissions that have required their utilities to offer DSM have concluded that DSM can be valuable to LDCs and other gas suppliers and their customers in a competitive and unbundled environment:

1. Some customers may prefer less reliable service in exchange for lower costs. DSM provides an opportunity for customers to exercise some control over use and the attendant costs. Competition with electric utilities may also drive some decisions regarding DSM.

2. For a gas supplier, the financial risks associated with underestimating gas needs during critical periods may make DSM more attractive than incurring financial penalties (e.g., high gas costs, high pipeline costs, penalties).

In some cases, state commissions ordered utilities to undertake DSM programs, at least on an experimental basis, to determine the potential value of DSM. In some instances, the cost of the programs exceeded the benefits of the programs that would likely prevail in a competitive market. In a competitive market, it seems more likely that DSM will be undertaken by customers and energy suppliers when it is cost-effective for them to do so. These competitive market decisions will be stimulated by having LDCs unbundle their rates.

In California, for example, Pacific Gas & Electric Company invested $47 million in gas DSM (compared to $177 million for electric DSM). PG&E realized first year savings of 22 million therms. Most of the savings were in the Industrial Class. PG&E has DSM programs for: 1) efficiency in agriculture, commercial and industrial applications, 2) residential appliance efficiency rebates and super-efficient homes, 3) apartment efficiency 4) low-income customers to improve energy efficiency, PG&E also spent $6.4 million on load research.[41] In Wisconsin, gas companies have considerable experience with DSM. Natural Gas, for example, has implemented DSM all types of customers. One of the more innovative is a "Commercial Kitchen & Restaurant Program".[42] In Indiana, Southern Indiana Gas & Electric Company may have the most ambitious Demand-Side Management programs. SIGECo's gas DSM programs include the following:

- **Residential Comprehensive Weatherization Pilot Program:** Initiated Jan. 1995. This program provides a package of weatherization measures to reduce natural gas and electric energy use among...800 homes. Participants are placed into common groups (e.g., gas heating, age of house, income). Gas savings, as a result of insulating ducts, ceiling insulation and sidewall insulation are estimated to be about 7,500 mmBtu per year (electric savings are 450kW and 1,100 MWh/year). The participants in the pilot do not pay any of the costs.

- **Residential New/Under Construction Pilot Program**: New Program. This pilot program provides financial incentives and utility certification for home builders to construct homes with energy-efficient practices. Natural gas savings are estimated at 470 mmBtu/year (electric = 30 kW and 20 MWh) or about 9% of total household energy use.

- **Residential Energy Low-Income Efficiency Financing Program:** New Program. Similar to the Weatherization Pilot, the RELIEF pilot provides zero-interest loans to low-income customers to pay for weatherization measures and/or high efficiency central cooling appliances to reduce electric and natural gas use. A low-income customer is defined as having a household income that is 125% of the national poverty level. Gas savings are estimated to be 2,185 mmBtu during the first year (electric = 121 kW and 194 MWh).

I. Economic Development Initiatives

Under the umbrella of "economic development initiatives", utilities and state regulatory commissions have developed "economic development", "load retention", and "special rates". These rates are intended to enable utilities to:

1) Attract new industry to their service areas,
2) Encourage existing industry to expand,
3) Assist existing industry to reduce their operating costs,
4) Improve the utilization of the utility's facilities.

In the vast majority of instances, utilities are required to charge more than the "incremental cost" (e.g., the cost of providing an additional unit of gas) of service. To the extent that the utilities recover more than the incremental cost, the margins are used to reduce the "fixed" costs. Contributions to fixed costs, in turn, should result in lower rates to other customers. It is, however, possible that the additional revenue would be obtained between rate cases and would only benefit shareholders.

Economic Development Rates

Of the states that regulate energy utilities (i.e., Nebraska does not have any investor-owned utilities, Tennessee does not regulate electric utilities since they are publicly-owned), thirty-nine state commissions have authorized "economic development rates. Fifteen states have authorized economic development rates for only electric utilities. As a result, many states have not approved economic development rates for gas utilities. In thirty-two states, utilities are allowed to offer economic development rates by special contract. While most states permit flexibility, twelve states have only permitted economic development rates to be fixed tariffed offerings.[43] For gas utilities, the majority of the rates that have been approved on a case-by-case basis and are intended to prevent "bypass" (losing customers to other suppliers).[44]

Load Retention Rates

Only nine states have not authorized their utilities to offer "load retention rates." Load retention rates are intended to enable utilities to discourage customers from leaving their systems. Of the forty-nine relevant states (excluding Nebraska), eight states have limited load retention rates to electric utilities. Correspondingly, twelve states have approved load retention rates for only gas utilities. Only six states require these load retention rates to be fixed tariffed offerings. [45]

Special Rates

Special rates (e.g., time-of-day, interruptible, "real-time") have been offered as a means of allowing customers to control their utility bills by tailoring their usage and reliability to their unique needs. Many utilities view these rates as "Demand-Side Management" programs. In some instances, these have also had the effect of promoting economic development and load retention. Only six states have not approved some form of special rates. It's noteworthy, however, that thirteen states have not authorized gas utilities to offer these rates. Thirty-seven states have authorized interruptible rates, thirty-two states have authorized "time-of-day" rates, and fifteen states have authorized "real-time" pricing.[46] Given that the costs that can be avoided by electric utilities resulting from reduced peak demand are greater than the costs that a gas utility can avoid, these special rates may be more applicable to electric utilities.

<u>Specific Examples</u>

California

The California Public Utilities Commission concluded that its long-run marginal cost methodology, that was adopted in 1992, was ineffective in producing a result similar to a competitive market. The Commission noted that the existing pricing policy significantly under-allocated costs of transmission and storage to customers with bypass potential. To assist the LDC in preventing bypass, the Commission allowed the LDC to offer discounted rates to large industrial customers. These anti-bypass rates did not recover the capital costs even though the LDC was investing over $100 million per year in the transmission system. The PUC also "rejected a proposal by the natural gas local distribution company (LDC) to continue shifting costs among customer groups to cover discounts awarded to customers with alternative energy supply options.

The Commission found that the anti-bypass rates were predicated on the believe that competition was imminent. To date, competition has not emerged. Nevertheless, the PUC reaffirmed its commitment to developing a competitive market for energy services. -Pacific Gas & Electric Co., A.94-11-015, D.95-12-053, December 20, 1995

Connecticut

The Connecticut Department of Public Utility Control (*Docket 95-02-07* October 13, 1995) required the Connecticut Natural Gas Corporation to increase its "target" profit margin on interruptible sales to large industrial customers to prevent cross-subsidization by smaller customers. Net margins, in excess of the target margin, would be shared between the ratepayers and shareholders. The Commission also encouraged the LDC to aggressively market its unneeded pipeline capacity and gas. The LDC was authorized to share profits between shareholders and ratepayers associated with "capacity release" and "off-system" sales. The Commission did, however, deny the Company's request to recover lost profits that resulted from large industrial customers switching from firm to interruptible service.

Maine

The Maine Public Utilities Commission has authorized Northern Utilities Company to offer a special rate to it's "extra large firm sales customers." The new rate is intended to allow large customers with relatively constant usage (i.e., high load factor) to receive lower rates.

Michigan

The Michigan PSC has reaffirmed an earlier decision requiring Consumers Power Company's gas LDC operations to absorb revenue losses associated with special discounts to large transportation companies (i.e., industrial customers). The Commission also order the LDC to reduce its ratebase by $11.7 million because the LDC had failed to prove that the discounts were justified by cost-of-service or that the load-retention rates resulted in any benefits to core customers. The PSC expressly rejected the Company's assertions that this would have an adverse effect on economic development and impede competition.

The Commission also upheld a previous decision that permits large industrial customers to combine their usage into 1 meter provided the customer's facilities are located near each other and operated as a single enterprise under common ownership. This allows smaller customers to avail themselves to discounted rates available to industrial customers. Case U-10755 June 5, 1996.[47]

New Mexico

The New Mexico PUC rejected a request by Public Service of New Mexico Gas Services to implement two new experimental "optional utility services." The services included: a) A food service maintenance program (to maintain and repair equipment) and b) an Energyguard Bill Payment program (insurance). The PUC concluded that it was inappropriate to treat these non-utility services as tariffed services. The Commission also expressed the following concerns: 1) that these services might be anti-competitive, 2) cause core customers to subsidize these services, and a lack of public access to the program records and cost information.[48]

IX. GLOSSARY

Advanced Combined Cycle Combustion Gas Turbines: An electric generating unit that is a combustion turbine installation that uses waste heat boilers to capture exhaust energy for steam generation.

Affiliates (see also subsidiaries)

Aggregators, Brokers and Marketers (ABMs)

Back-Up Service: Additional supply to assure reliability

Balancing: Reconciliation of actual takes versus forecasted (or nominated) use.

BCF: Billion Cubic Feet

BTU -British Thermal Unit: The standard unit for measuring quantity of heat energy, such as the heat content of fuel. It is the amount of heat necessary to raise the temperature of one pound of water on Fahrenheit degree. There are 1.03 million Btu in 1 Mcf and 3,412 Btu in 1 kWh.

Bypass: Allowing customers to purchase from a competitor to the traditional LDC supplier. In many cases, LDCs offered discounted rates as incentives to keep customers from switching suppliers.

Bundled Service: (see unbundled service)

Buy/Sell Arrangement: A buy/sell arrangement is a means of procuring gas supply where the ownership of the gas is transferred from the seller to the LDC for delivery to end-users. The LDC normally bills the buy-sell customer at its tariffed rate for system gas. The seller rebates to the customer the difference in price between the gas distributors cost of gas and the gas purchased from the seller.

Capacity: The physical capability of the facility (e.g., pipeline or power plant).

Capacity Factor: A measure of efficiency were: $\frac{\text{Average Load}}{\text{Rated Capacity}} \times 100$

Capacity Release: Selling back unneeded gas transmission capacity to the pipeline, marketers or other entities. In 1995, according to the Interstate Natural Gas Association (INGAA) about 15% of the gas moved on capacity that was released.

City Gate: A point of delivery (metering point) to the LDC from a pipeline.

Coincidence Factor: The ratio of coincident demand to the sum of the individual demands at a specific time. Most commonly, it is the ratio of an individual (or class of) customer's demand at the time of the system peak demand. This is used in Cost-of-Service Analysis to assign costs based on a customer's contribution to the utility's peak.

Combination Utility: Typically, this refers to a utility that serves both electric and gas.

Commodity Charge (see also Variable Costs)

Consumer Price Index: A measure of aggregate prices for commodities and services typically purchased by individuals (e.g., housing, food, health care, gas, electricity, autos, clothing). The index is generally used to gauge the change in average price levels for all commodities. By comparing the change in the price of any commodity to the change in the Consumer Price Index over a period of time, on can estimate the "real change" (i.e., the net price of general inflation in the economy) for that commodity.

Core Market: Customers that do not have competitive options and are therefore captive to a single supplier.

Correlation (also used as Correlation Coefficient): A measure of the linear association between two variables, calculated as the square root of the R^2 obtained by regressing one variable against another. Correlation ranges from -1 to +1. Correlation values close to -1 or +1 show a strong correlation between the two variables (inversely proportional or directly proportional respectively). Correlations close to zero show no correlation.

Cost-of-Service (COS): A method of allocating the costs of providing service to individual customers. Typically, there are three components of cost-of-service: classification, functionalization and allocation of costs. COS attempts to correlate utility costs and revenues with the service that is provided to each customer (more typically a class of customers).

Cubic Foot: A unit of volume equal to 1 cubic foot at a pressure base of 14.73 pounds standard per square inch absolute and a temperature base of 60° F.

Customer Class: Typically, residential, commercial and industrial customers are designated as separate classes. It is not uncommon to have subclasses such as residential spaceheating customers. These are groups of customers with similar characteristics.

Decontracting: "Pipeline customers (shippers) that fail to renew their contracts for firm transportation services". The Grey Market is used to resell this unused capacity.

Deflator: (see also Consumer Price Index) An index which is used to adjust for the purchasing power of a dollar.

Demand: In economic terms, it is the inverse relationship between the price of a good and the quantity of the good that is demanded. In utility terms, it is the instantaneous (or over any specified time interval) load on the utility.

Demand Charge (see also Fixed Costs) It is the amount charged to a customer (or customer class) to reflect that customer's use during a specified time interval. In Cost-of-Service analysis, the demand charge is typically based on the fixed costs associated with serving customers.

Demand-Side Management: The planning, implementation and monitoring of utility activities designed to influence customer use of electricity in ways that will produce desired changes in a utility's load shape (i.e., changes in the time pattern and magnitude of a utility's load). Utility programs falling under the umbrella of DSM include: load management, energy efficiency, energy conservation, and innovative rates.

Derivatives: SFAS No. 119 defines derivatives as a "financial instrument is a future, forward, swap or option contract, or other financial instrument with similar characteristics." A derivative is a financial instrument that derives its value from the value of other financial instruments or an underlying asset such as a commodity, futures contract, stock, bond, currency, index or interest rate.

Efficiency: The ratio of inputs ÷ outputs.

Elasticity: The ratio of the percentage change in one variable to the percentage change in another variable, where X and Y represents variables and to represents time (e.g., the price of gas and the demand for gas over time).

Electronic Bulletin Boards (EBBs see also GISB): A means of communicating the prices and availabilities of different unbundled services.

End-Use: Uses of energy including, but not limited to, space heating, water heating, lighting, air conditioning, refrigeration.

End-Use Load Research: Load research conducted for end-use equipment. This is done by metering these specific end uses.

Federal Energy Regulatory Commission (FERC) An independent agency created within the Department of Energy. The FERC is the successor of the Federal Power Commission (FPC) on September 30, 1977. The FERC is vested with broad regulatory authority over interstate sales of gas and electricity.

Firm Capacity (FT) short and long-term firm

Fixed Costs (see also Demand Charges)

Gathering Facility: A facility used to combine the gas from different gas wells for delivery to the pipelines.

GCA - Gas Cost Adjustment Clause (see detailed discussion)

GISB - Gas Industry Standards Board Provides for standardization of nomination practices and information pertaining to transportation services using the internet. Order 587-Final Rule adopts 140 standards submitted by the GISB. see Standards for Business Practices of Interstate Natural Gas Pipelines, Docket No. RM96-1-000, 75 FERC ¶61,077. April 26, 1996. The FERC noted that much work needs to be done and set a September 30, 1996 deadline for the GISB to submit additional proposals to encompass all electronic information provided by pipelines.

Gray Market (see Secondary Market and Capacity Sell Backs)

Gross Domestic Product (GDP): Considered to be the best measure of the aggregate value of national output. GDP is equal to the Gross National Product net of residents' income from economic activity abroad (e.g., exports, repatriated profits, interest) and property held abroad minus the corresponding income of non-residents in the country (e.g., imports, profits and dividends taken out of the country).

Gross National Product (GNP): The total dollar value of market oriented goods and services produced by the United States economy. While the proper accounting adjustments are made, this is equivalent to adding up total income, taxes in the economy, or total sales or purchases or the total value of each industry's output.

GSR Gas Supply Realignment Costs (transition costs). This was an attempt to resolve the take-or-pay problem that plagued the industry during the 1980s. Under Order 636, pipelines had to realign their contracts. First, they could try to assign the contracts to former customers. The second option were to be reformed to reflect current market conditions. Of the costs incurred in reforming the contracts, 90% were allocated to firm transportation customers while 10% were allocated to interruptible customers. By June 30, 1992 pipelines agreed to absorb $3.6 billion of the estimated $10 billion in take-or-pay stranded costs. The remaining balance of $7.4 billion would be paid by consumers. Account 191 provided for direct billing of other stranded costs.

The U.S. Court of Appeals for the District of Columbia No. 92-1485 July 16, 1996 held that FERC must reconsider the allocation of 10% of GSR costs to interruptible customers and explain why pipelines can pass through all of their GSR costs to customers in light of the equitable sharing procedures in Order 500 and the general cost-spreading principles in Order 636.

Heating Degree Days (HDD): A measure of how cold a location is relative to a base (normal) temperature over a period of time. The heating degree days for a single day is the difference between the base temperature and the days average temperature. If the daily average is greater than or equal to the base, this would be a "zero" heating degree day.

Hedging: The difference between a pre-arranged price and the sum of 1) the cash market city-gate price as quoted by a commodity price index, 2) a previously agreed upon retailing markup and 3) LDC transportation charges relevant to that consumer.

Hubs: Where two or more pipelines interconnect such as the Henry Hub in Louisiana and the Moss Bluff Hub in Texas. Some practitioners use the terms "Hub" and "Market Center" interchangeably. Mechanisms to reduce the volatility of prices between various regions of the country by reducing operational and informational inefficiencies. Hubs organize trading activity at locations where prices on gas, storage, pipeline, and other services are available to all participants in the hub market, and where daily trading may be active enough to provide liquid markets.

Implicit Price Deflator: The economy's aggregate price index. Defined as the ratio of nominal GNP to real GNP.

Inflation Rate: The rate of change in the economy's price level.

INGAA: Interstate Natural Gas Association of American. An association of natural gas pipelines.

Interruptible Capacity (IT) According to a 1995 survey of its members by INGAA, interruptible transportation amounted to 51% in 1987 and remained fairly constant (55%, 55%, 51% and 49%) until 1992 (Order 636) when IT accounted for 42% of all gas transported. Since 1992, the amount of IT has dropped to 14% for the first half of 1995 (35% and 19% during the years 1993-1994).

LNG: Liquified Natural Gas. Gas that has been liquified by reducing its temperature to minus 260o Fahrenheit at atmospheric pressure.

Load Curve: *A graph that shows the shape of demand for gas (electricity) over a specified period of time (e.g., a day, month, season, year).*

Load Duration Curve: A graph that shows the amount of time that gas (electric) demand is at a particular level. Demands are usually ordered from the highest to the lowest on the vertical axis. Time (e.g., a year) is on the horizontal axis.

Load Factor: The ratio, expressed as a percent (100) of the average load supplied during a designated period (e.g., hour, day) to the peak demand.

$$\frac{\text{Average Demand}}{\text{Peak Demand}} \times 100 \quad \text{or} \quad \frac{\text{Energy}}{\text{Peak Demand} \times \text{Time}} \times 100$$

Load Research: (see also End-Use Load Research) Analysis of gas (or electric) usage data to better understand when and how customers use energy. This data is typically used to support load forecasting, cost-of-service and marketing programs.

Local Distribution Company (LDC): An LDC is the utility that is responsible for delivering gas to the customer behind the city gate (where the pipeline delivers gas to the LDC).

Long Run: A period of time that is long enough to permit the variation of all inputs to production including capital and technological change. By way of example, long term usually describes fixed costs. Purchases of spot gas would be an example of short term costs.

Major Interstate Pipeline: A company whose combined sales for resale, and gas transported interstate or stored for a fee, exceeded 50 million thousand cubic feet in the previous year.

Marginal Cost: The change in total costs associated with a unit change in the quantity supplied. The cost of providing an additional Mcf or KWh.

Market Center: A market center has been defined as a Hub that has a pipeline, marketer or other entity identified as the operator of the interconnection. Defined as: "A market center is an area where (a) pipelines interconnect and (b) there is a reasonable potential for developing a market institution that facilitates the free interchange of gas." -FERC's Order 636-B, November 27, 1992.

MCF: Thousand Cubic Feet. 1 Mcf of gas = 1.03 million Btu (also, 1 kWh = 3.4 thousand Btu).

Mean: The average = $\frac{\sum \text{(observations)}}{\text{Number of Observations}}$

MMBtu: Million British Thermal Units

MMCF: Million Cubic Feet

Natural Gas: A mixture of hydrocarbons (principally methane) and small quantities of non-hydrocarbons existing in the gaseous phase or in solution with crude oil in underground reservoirs.

No Notice Service: Rebundled pipeline services.

Nominal: An adjective that describes any monetary magnitude measured in current rather than "real" dollars. For example, Nominal Total Personal Income is the current dollar value of Total Personal Income through time not adjusted to reflect the general levels of price increase in the economy through time

***Non-Coincident Peak Demand** (NCP):* The sum of two or more individual demands which do not occur in the same (coincident) time interval. Mathematically, the NCP can be equal to but is almost always greater than the coincident peak demand.

Non-Firm Purchase: An "as available basis. There is no commitment to serve.

On System Sales: Sales to customers where the delivery point is a point on, or directly interconnected with, a transportation, storage, and/or distribution system operated by the reporting company.

Peak Demand: The maximum amount of gas (electricity) that is consumed during a specified period of time (e.g., an hour).

Performance-Based Rates: Sometimes referred to as "Incentive Rates", PBRs may take many forms including: "price caps", "yardstick regulation" (e.g., comparing a utility to other utilities), "sliding scale" regulation (i.e., where the customers and the shareholders share benefits and costs), or hybrids.

Price Elasticity: The ratio of the percentage change in demand for a good to the percentage change in the price of that good. Demand is considered to be elastic when the ratio exceeds 1 and inelastic when it is less than 1.

Rate Base: The value of a utility's property, established by the IURC, upon which the utility is allowed to earn a specified return.

Rate-of-Return: The ratio of allowed operating income to a specified rate base expressed as a percentage.

Real: A price that has been adjusted to remove the effects of changes in the purchasing power of the dollar. A real price reflects changes in the value relative to a base year (e.g., 1990)

Real Gross Domestic Product: Real GDP is the figure derived by deflating each component of the GDP for the general level of increase in prices.

Reliability: The assurance of system performance at all times and under all reasonable circumstances to ensure quality, adequacy and economy of gas.

Secondary Market: In the gas industry, this is the market for re-selling unneeded pipeline capacity.

Shippers: Another name for customers (e.g., industrial, LDC)

Spot Gas: This is typically gas that is purchased on a short term basis and is furnished on an as available basis.

Storage: Storage may take the form of underground storage in salt caverns, abandoned gas/oil well or in above ground containment vessels such as liquified natural gas.

Straight-Fixed Variable Pricing: The FERC approved SFV for pipelines to have a higher degree of assurance that their costs would be covered by customers. All fixed costs would be allocated to customers according to their peak day entitlement. In other words, SFV rate design allows pipelines to recover most of its costs through the demand component, rather than the commodity component. As a consequence, customers that have a relatively low load factor (peak demand in relation to average use) pay more than those customers that have a relatively constant usage pattern throughout the year.

Tcf: Trillion Cubic Feet

Therm: One-hundred thousand British Thermal Units.

Unbundling: *(See detailed discussion)*. Generally, this involves the separation of various services upstream of the LDC (e.g., production, transmission and storage). For an LDC, unbundling might include: transforation, metering, billing, storage, backup, and balancing).

Variable Costs: The opposite of fixed costs. These are costs that vary over time (e.g., the cost of purchasing gas)

Wellhead: It is a term to describe the production fields. The wellhead price of natural gas at the source. Usually, this is the total price delivered to the City Gate minus transportation and storage costs.

Working Gas: The volume of gas in an underground storage reservoir above the designed level of the base. It may or may not be completely withdrawn during any particular withdrawal season. Conditions permitting, the total working capacity could be used more than once during any season.

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2. "Annual Energy Review 1995", United States Department of Energy/Energy Information Administration, July 1996, page 7.

3. Ibid, page 11

4. "New Directions: Natural Gas Industry", Natural Gas Council, 1992

5. "Gas Daily", April 1996.

6. "New Directions: Natural Gas Industry", Natural Gas Council, 1992.

7. Indiana Utility Regulatory Commission, Cause No. 32485, Arlington Natural Gas Co et al., pg.8.

8. Burns Annotated Indiana Statutes. Code Edition. Title 8, Articles 1-4. 1991 Replacement Volume.

9. Public Service Commission v. Indianapolis Rys., supra, 1948, 225 Ind. 656, 76 N.E.2d 841.

10. "Utility Regulatory Policy in the United States and Canada: Compilation 1994-1995", National Association of Regulatory Utility Commissioners, August 1995.

11. IURC Cause No. 32485.

12. "Utility Regulatory Policy in the United States and Canada: A Compilation 1994-1995", National Association of Regulatory Utility Commissioners, August 1995.

13. "Utility Regulatory Policy in the United States and Canada: A Compilation 1994-1995", National Association of Regulatory Utility Commissioners, August 1995.

14. Pierce, Richard J. Jr. "Reconstituting the Natural Gas Industry from Wellhead to Burnertip" Energy Law Journal, Vol. 9 No.1, 1988.

15. "Report of the FTC to the U.S. Senate", S.Doc. No. 92, 70th Congress 1st Session, pt 84-A, (1936).

16. Commonwealth Edison Co. v. Montana, 453 U.S. 609, 650 1981.

17. Public Utility Holding Company Act Amendments: Hearings on S.1869, S. 1870, S. 1971 and S. 1977. Before the Subcommittee on Securities of the Senate Commission on Banking. Housing and Urban Affairs 97th Congress 2nd Session 350-354 (1982) Comments by Ronald G. Carr, Deputy Assistant Attorney General and William F. Baxter, Assistant Attorney General.

18. "Oil and Gas Journal" August 10, 1987 page 20.

19. "The Effect of Restructuring on Long-Term Contracts for Interstate Pipeline Capacity" Interstate Natural Gas Association of America (INGAA) September 1995 The INGAA noted:

> *96% of pipeline capacity was under firm contracts...which included 4% under short-term firm contracts. Contracts for nearly half of pipeline capacity will expire between 1995-2002. Between 1994 and 2002, the amount of contracted firm capacity is expected to decline from 96% to 87% of total capacity. Long-term contracts will be of shorter duration. Over half of the resubscribed capacity will be for contract terms of 4 years or less.*

20. "Natural Gas Monthly" January 1991 pages 1-9 Just as some customers did not benefit as much as others, there were also losers in the gas industry as well. Two interstate gas pipelines and several gas producers went into bankruptcy or default. The most notable bankruptcy of a gas pipeline was Columbia Gas. Columbia Gas emerged from bankruptcy in 1995. By November 1, 1990, pipelines paid a total of $9.1 billion to settle take-or-pay disputes with producers. This was the greatest portion of the gas stranded costs. Of this, $5.4 billion was eligible for recovery under Orders 500 and 528.

21. *World Energy Survey of Natural Resources,* Based on 21,480 Btu/lb to 23,450 Btu/lb, London 1992. As reported in the *Gas IRP Review* a publication of the Gas Research Institute, June 1996. In general, a combined cycle unit uses exhaust heat from the gas combustion turbine to super heat steam for use in a boiler.

22. "Annual Energy Review 1995", United States Department of Energy/Energy Information Administration, page 251, July 1996.

23. "Effect of Electric Industry Restructuring on the Competitive Price Position of Natural Gas", R.J. Rudden Associates, 1996.

24. "Annual Energy Review 1995", United States Department of Energy / Energy Information Administration, July 1996.

25. Rosenberg, William Former Assistant Administrator of the EPA's Office of Air and Radiation. *Hart's Natural Gas Focus,* June/July 1996, page 24.

26. "Unbundling the Retail Gas Market: Current Activities and Guidance for Serving Residential and Small Customers", The National Regulatory Research Institute, May 1996, page 8.

27. "Unbundling the Retail Gas Market: Current Activities and Guidance for Serving Residential and Small Customers" The National Regulatory Research Institute, May 1996, page 15.

28. NRRI page 29.

29. PUR UTILITY WEEKLY, March 15, 1996, page 1.

30. Case Nos 94-1405-GA-AEC et. al., The Ohio Public Utilities Commission, April 11, 1996.

31. Fidelity Natural Gas Company, Case No. GT-96-134, January 30, 1996 168 PUR4th, page 347, April 11, 1996.

32. "INSIDE FERC" September 2, 1996, pages 1, 8 and 9.

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34. U.S. West Communications, UT80 Order No. 96-107, April 24, 1996.

35. "Public Utilities Fortnightly", re: Minnegasco Docket No. G.-008/M-95-465, (May 21, 1996), September 1, 1996, page 46.

36. "Unsubscribed Interstate Pipeline Capacity: Response of Publicly-Owned Gas Distributors", American Public Gas Association, May 1996.

37. Public Utilities Fortnightly January 1, 1994 pages 23-26

38. Ibid.

39. "Gas Market Evaluation", GAS IRP REVIEW, GRI, Jan/Feb 95.

40. "1995 Integrated Resource Plan" Southern Indiana Gas & Electric Company November 1, 1995 beginning at Chapter 4.

41. Gas Research Institute, March/April 1994, pages 1-4.

42. Ibid, pages 4-6.

43. "Utility Regulatory Policy in the United States and Canada: A Compilation 1994-1995", National Association of Regulatory Utility Commissioners, August 1995.

44. "Financial Analysis: Local Distribution Company Unbundling and Deregulation Activities", American Gas Association, July 1995.

45. IBID.

46. IBID.

47. "Public Utilities Fortnightly", September 1, 1996, page 47.

48. "Public Utilities Fortnightly", September 1, 1996, page 48.